# EVALUATION OF ALTERNATIVES FOR TRANSPORTATION AND UTILIZATION OF ALASKAN NORTH SLOPE GAS

# SUMMARY REPORT



APRIL 1983

BOOZ • ALLEN & HAMILTON INC.

BOOZ·ALLEN & HAMILTON INC.
4330 EAST WEST HIGHWAY · BETHESDA, MARYLAND 20014 · TELEPHONE: (301) 951-2200 · TELEX: 751-824-0552

June 9, 1983

Honorable Esther C. Wunnicke
Commissioner of Natural Resources
State of Alaska
Pouch M
Juneau, Alaska 99811

Dear Commissioner Wunnicke:

Enclosed is Booz, Allen's final report to the State Task force, entitled Evaluation of Alternatives for Transportation and Utilization of Alaskan North Slope Gas.

We have enjoyed the opportunity to work closely with you and your key staff members, particularly with Mr. Mark Wittow, on this most interesting and challenging assignment. We were also pleased that our draft report, and Ben Schlesinger's testimony last March, were both well received.

If you or any other members of the task force have any questions or comments, please do not hesitate to call me or Ben Schlesinger (301/951-2510).

We look forward to working with you again in the future if the need should develop.

Very truly yours,

Bruce Pasternack

BOOZ · ALLEN & HAMILTON Inc.

Bruce A. Pasternack
Vice President

Enclosure

# TABLE OF CONTENTS

TABLE OF EXHIBITS

TABLE OF EXHIBITS (Continued)

TABLE OF EXHIBITS (Continued)

## GLOSSARY OF TERMS

| | |
|---|---|
| ADNR | Alaska Department of Natural Resources, whose Director chairs the State Task Force on North Slope Gas Alternatives |
| ANGTA | Alaska Natural Gas Transportation Act of 1977, which granted ANGTS (see below) preference |
| ANGTS | Alaska Natural Gas Transportation System, the proposed 48" gas pipeline to the lower 48 states (also sometimes referred to as the Alcan Highway Pipeline, and the Northwest Alaskan Pipeline) |
| ANS | Alaskan North Slope |
| AOGCC | Alaskan Oil and Gas Conservation Commission, whose approval is necessary to undertake any gas sales or EOR |
| Bcfd | Billion cubic feet per day |
| DOE | U.S. Department of Energy |
| EIA | Energy Information Administration, a branch of the U.S. Department of Energy, which prepares forecasts, analyses and statistics about energy |
| EIS | Environmental impact statement required of any major Federal action or project approval |
| EOR | Enhanced oil recovery |
| ERA | Energy Regulatory Administration, a branch of the U.S. Department of Energy, whose approval is needed for any energy import or export |
| FERC | Federal Energy Regulatory Commission, whose approval is needed to enable construction of gas pipelines in the U.S. |
| LNG | Liquefied Natural Gas |
| MBD | Millions of barrels per day (one MBD for a year roughly equates in energy content to 2 trillion cubic feet of natural gas) |
| MMBtu | Million Btu (British thermal units); a measurement of the energy content of different fuels, and thereby a common yardstick for comparing fuel prices. A Btu is the energy needed to raise the temperature of a pound of water by 1 degree Farenheit. |
| MMT | Million metric tons; the typical measurement means for LNG and other liquids (e.g., crude oil) imported by Japan |

GLOSSARY OF TERMS (Continued)

| | |
|---|---|
| NGPA | Natural Gas Policy Act of 1978 which, among other provisions, gradually increases U.S. natural gas field prices and decontrols most flowing gas beginning in 1985 |
| TAGS | Trans-Alaska Gas System, the proposed 36" pipeline to Kenai primarily for LNG sales to Pacific rim markets |
| TAPS | Trans-Alaska Pipeline System, the existing crude oil pipeline to Valdez, also known as the Alyeska pipeline |
| Tcf | Trillion cubic feet |

# I. EXECUTIVE SUMMARY OF KEY FINDINGS

Since massive oil and natural gas deposits were discovered at Prudhoe Bay 14 years ago, many transportation/marketing alternatives have been discussed to utilize the natural gas resources. In 1977, after much debate, the Congress enacted the Alaskan Natural Gas Transportation Act, which resulted in approval of a 4800-mile pipeline to the Midwest and Pacific states, generally following the Alcan Highway across Alaska and Canada (the Alaskan Natural Gas Transportation System--ANGTS). When ANGTS was approved, the Nation was suffering a severe natural gas shortage brought on by wellhead gas price controls; consequently, there was strong interest in bringing Alaskan gas and other supply supplements to market. Now, however, the domestic natural gas supply/demand picture has changed. Supplies are abundant and prices have generally reached market levels, and ANGTS has not yet begun construction because of financial and market uncertainties.

For this reason, the State of Alaska Task Force on Alternative Uses of North Slope Natural Gas commissioned Booz, Allen & Hamilton and its team of subcontractors--the firm of Homan-McDowell in Juneau, and Van Ness, Feldman, Sutcliffe, Curtis and Levenberg in Washington, D.C.--to assess a broad array of North Slope gas options. The purpose of the Booz, Allen analysis is to identify the few leading North Slope gas options, and for each of these, evaluate the economic, financial, technological, regulatory and social aspects in light of current and prospective economic conditions, energy costs and markets. In addition, the State of Alaska also sponsored two other key studies about North Slope gas:

- The **Governor's Economic Committee**, headed by former Governors Hickel and Egan (assisted by Brown and Root; Dillon, Read; Mitsubishi Research Institute; and others), evaluated an intrastate gas system for ultimate transport and sale of North Slope gas, largely as LNG into Pacific Rim markets (known as the Trans-Alaska Gas System--TAGS)
- The **Alaska Power Authority** commissioned Ebasco to evaluate alternate systems that would utilize North Slope gas directly in Alaska to generate electricity.

This document presents the results of the Booz, Allen analysis, and briefly summarizes the approach which we used in our evaluation of North Slope gas options. With the limited time and resources available, it was recognized that this analysis could not be at the same level of depth as other studies of individual North Slope gas options, but would rather be an overall comparison of options in light of recent market and economic conditions.

## 1. A WIDE RANGE OF NORTH SLOPE GAS UTILIZATION OPTIONS WAS NARROWED TO FIVE MOST PROMISING NEAR-TERM ALTERNATIVES

The large number of transportation, processing and end-use product markets that exist for utilizing North Slope gas was narrowed based on a review of project economics, markets, value-added to Alaska, technological risks, and other factors. A full description of the screening approach is contained in Booz, Allen's Phase I report (Evaluation of Alternatives for Transportation and Utilization of Alaskan North Slope Gas: Phase I Report, Booz, Allen & Hamilton Inc., November 1982).

We narrowed the field of study to five options for use of North Slope gas (as illustrated in Exhibit I-1):

- Conventional gas pipeline to the Lower 48 states, following the Fairbanks/Alcan Highway route (the ANGTS project)
- A high-pressure gas line carrying untreated gas to the Kenai Peninsula, for conditioning and gas liquefaction, with LNG shipment to Pacific Rim markets (the TAGS project)
- Utilizing gas for **electricity generation** in the Fairbanks area, with gas transport provided either through ANGTS, TAGS, or via a small diameter pipeline to Fairbanks, one of the options evaluated in the APA/Ebasco study
- Gas conversion into **methanol** at a plant located near Fairbanks, for eventual sale into Pacific Rim markets; again, transport from the North Slope could be effected by either the TAGS or ANGTS lines (a project proposed by Alaska Interior Resources Co., Inc.)
- Gas used on the North Slope for **enhanced oil recovery** (EOR), as suggested in ARCO's water/alternated with gas injection proposal recently approved by the State Oil and Gas Conservation Commission.

Salient operating and cost characteristics of the five projects are summarized on Exhibit I-2. The projects selected provide a representative range of transportation, product type, project size and market options. Additionally, the ANGTS and EOR projects provide a benchmark for evaluating all five options; ANGTS constitutes the currently approved project for North Slope gas utilization, while EOR represents an option that does not involve development of facilities for purposes of gas sales.

The next sections present our findings and recommendations for the State of Alaska.

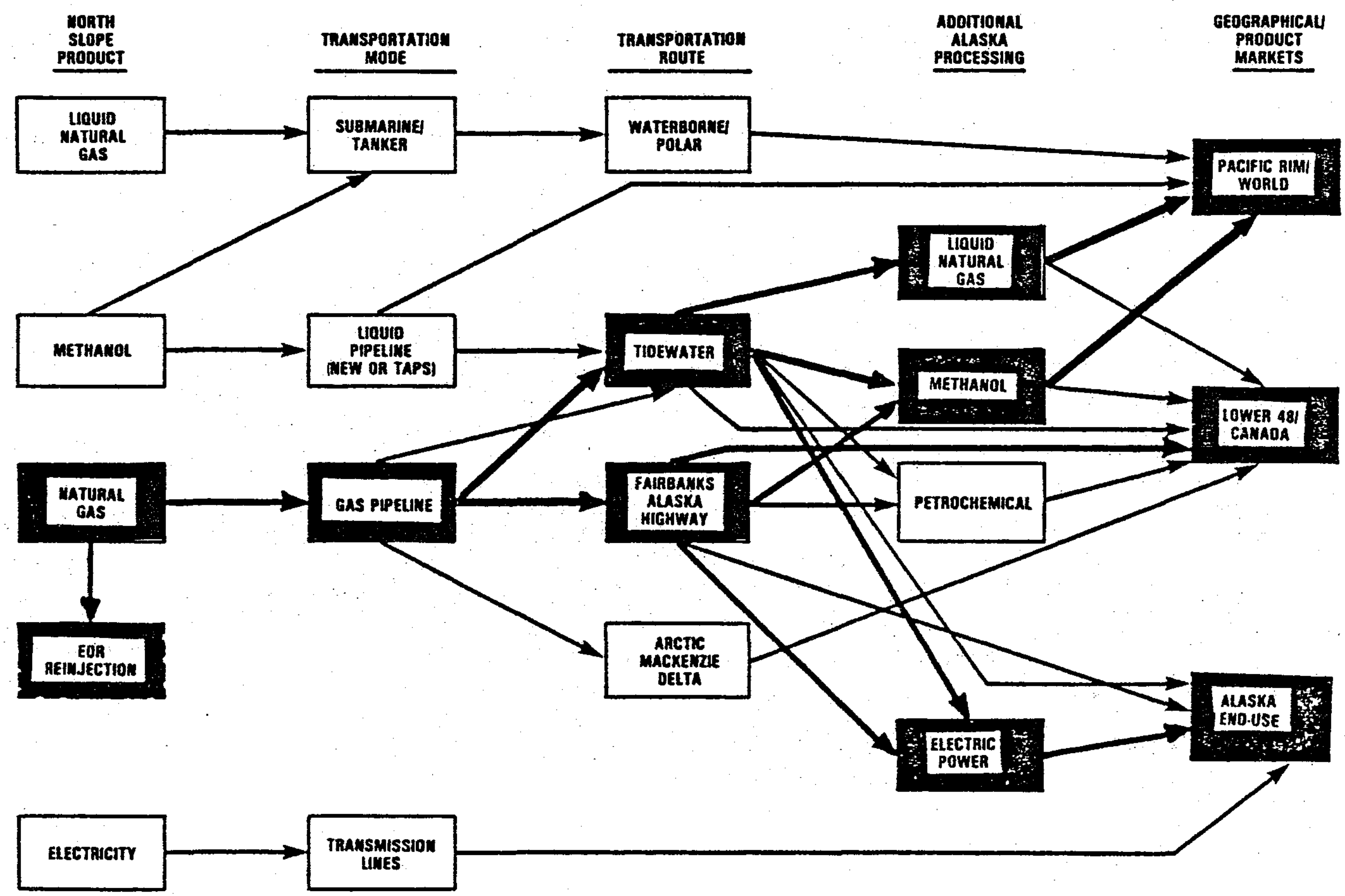
## 2. THE STATE OF ALASKA WOULD BENEFIT SIGNIFICANTLY FROM COMPLETION OF EITHER LARGE-SCALE GAS PROJECT—ANGTS OR TAGS

The two large-scale gas transport/marketing options we evaluated--TAGS and ANGTS--are in varying stages of development and, in a sense, are competing against each other. It is clear that major economic benefits would accrue to Alaska if either big project were to proceed:

- Tax and royalty returns to the State would be increased by $220-356 million per year on the average over 20 years, for ANGTS and TAGS, respectively (in 1982 dollars). Total revenue benefits -- including royalty payments and severance, property and income taxes -- the State would receive are:
  - $3.3-4.4 billion from ANGTS in most oil price cases
  - $5.6-6.9 billion from TAGS
  - $26-62 million from developments at Fairbanks

Exhibit I-1

NORTH SLOPE GAS OPTIONS SELECTED FOR STUDY EVALUATION



## Exhibit I-2

## SALIENT CHARACTERISTICS OF PROJECTS SELECTED

| PROPOSED PROJECT | ESTIMATED CAPITAL COST[1] (MIL. 1982 DOLLARS) | GAS REQUIREMENTS (BCF/YEAR) | MAJOR PROJECT COMPONENTS | MAJOR PRODUCT(S) | MAJOR MARKET(S) |
|---|---|---|---|---|---|
| ALASKAN NATURAL GAS TRANSPORTATION SYSTEM (ANGTS) | \$23.488[4] | 766.5 | 4800-MILE PIPELINE (730 MILES IN ALASKA); NORTH SLOPE GAS CONDITIONING PLANT | NATURAL GAS | LOWER 48 STATES |
| TRANS-ALASKA GAS SYSTEM (TAGS) | \$14,294[2] | 346.75[3] (PHASE I); 1032.95[3] (FULL SYSTEM) | 820-MILE ALASKAN PIPELINE; GAS CONDITIONING AND LIQUEFACTION PLANT ON KENAI PENINSULA | LNG NATURAL GAS LIQUIDS (NGLs) | JAPAN; OTHER PACIFIC RIM |
| METHANOL PLANT | \$575-\$725 | 50.0 | METHANOL PLANT; ELECTRICITY CO-GENERATION PLANT (125 MW) AT FAIRBANKS | METHANOL ELECTRICITY | JAPAN; OTHER PACIFIC RIM; FAIRBANKS |
| ELECTRICITY GENERATING STATIONS | \$590-\$1121 | 4.5 INITIALLY, RISING TO 38-73 | GENERATING STATIONS AT FAIRBANKS (726-1386 MW); HIGH-VOLTAGE TRANSMISSION LINE THROUGH RAILBELT | ELECTRICITY | ALASKA RAILBELT |
| ENHANCED OIL RECOVERY (EOR) | UNKNOWN | 800 (EST'D) | NORTH SLOPE GAS TREATMENT FACILITY; REINJECTION WELLS | OIL | U.S. WEST & GULF COASTS |

SOURCES: NORTHWEST ALASKA PIPELINE (ANGTS); REPORT OF THE GOVERNOR'S ECONOMIC COMMITTEE (TAGS); ALASKA INTERIOR RESOURCES, INC. (METHANOL); APA/EBASCO (ELECTRICITY); ARCO (EOR)

FOOTNOTES:
1. EXCLUDES FINANCING COSTS.
2. FOR FULL SYSTEM.
3. RAW GAS (INCLUDES 12.5% $CO_2$, AND ASSOCIATED NGLs).
4. INCLUDES "PRE-BUILT" SYSTEM COSTS.

- A large number of direct jobs would be created in Alaska in either case, as below on a per-year basis:

| | ANGTS | TAGS |
|---|---|---|
| - Construction | 4615 | 3070 |
| - Operation | 319 | - 435 |

- Nearly twice again as many jobs would be created indirectly, assuming a multiplier of 1.8 for induced employment. This estimate is likely to be conservative because it derives from a time when Alaska's economy was less developed than it is expected to be in the 1990's and beyond, when these jobs would be created.

- Additional employment would be created in Alaska to the extent either large-scale gas project were to enable added gas and liquids processing facilities (e.g., petrochemicals).

Thus, on the basis of in-state benefits, it appears to be in the State's interest to support North Slope gas development per se, and to be largely indifferent as to which project is ultimately completed.

## 3. DESPITE THEIR DIFFERENCES IN CONFIGURATION AND TRANSPORTATION MODES, ANGTS AND TAGS APPEAR ABLE TO DELIVER GAS TO CUSTOMERS AT SIMILAR COSTS

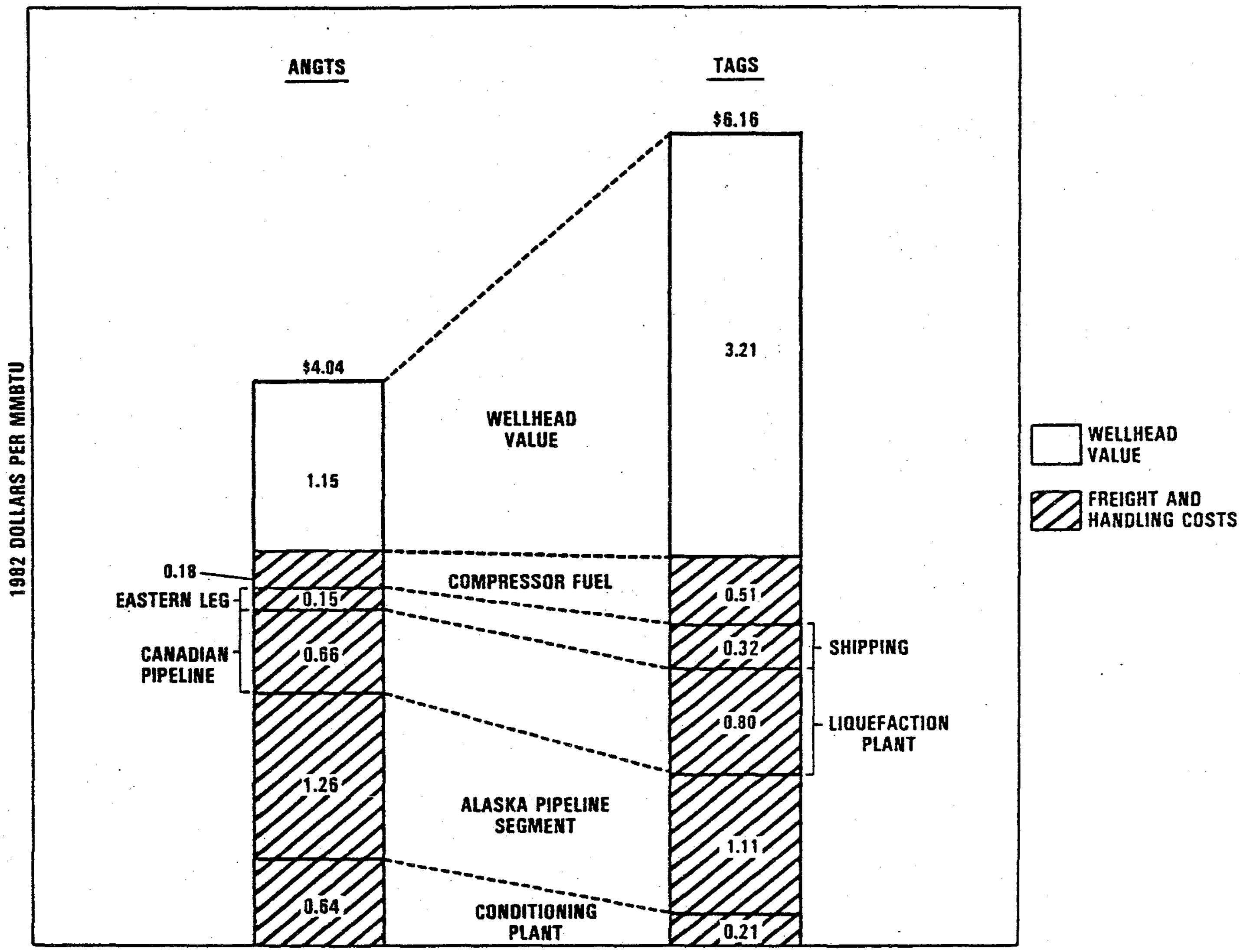
It should be emphasized that this analysis does not involve an engineering comparison of estimated capital costs for either ANGTS or TAGS. In general, it is recognized that project cost estimates for ANGTS have the benefit of five years of design, engineering and testing, and must therefore be viewed as considerably more firm than those for TAGS.

Nevertheless, based on given construction cost information available from the project sponsors (in the case of ANGTS) and from the Governor's Economic Committee (for TAGS), we conclude that the "freight and handling" expenses for the two projects are unlikely to differ substantially, in terms of the cost to deliver gas to their respective customers.

For both TAGS and ANGTS, Exhibit I-3 compares "freight and handling" costs--which includes all transportation, conditioning, and other processing steps up to the point of delivery--on the average for the first twenty years that each project is to operate. As shown on this exhibit, the Alaskan pipeline segment is the largest cost element for both projects, with TAGS showing some advantage (about 10-15 percent) due to its proposed construction approach. This advantage is offset, however, by the somewhat higher processing and marine transportation costs of TAGS, compared to ANGTS; i.e., projected liquefaction and tanker shipment costs of TAGS (about $1.12 per MMBtu) are higher than the additional pipeline segments of ANGTS (about $0.81 per MMBtu). Although TAGS estimates for the cost of gas conditioning are far lower than those for ANGTS, it is unclear whether these estimates, or those for the TAGS pipeline, are as well developed as ANGTS estimates. Furthermore, the possibility that ANGTS may be able to adopt some of the construction techniques suggested for TAGS was not evaluated in this analysis.

Exhibit I-3

COMPARISON OF AVERAGE PROJECT COST COMPONENTS AND WELLHEAD GAS VALUES FOR ANGTS AND TAGS




Note: Cost components based on "baseline case" pipeline costs; wellhead value calculated under "weaker economy" price case.

Moreover, some argue that the "incentive rate of return," which links ANGTS earning levels to avoidance of cost overruns, provides its sponsors with an incentive to overestimate project construction costs, and thereby assure themselves of the maximum allowed returns on equity. Quite the opposite situation is true with respect to TAGS. Some argue that project proponents have an incentive to minimize prospective costs, and thereby secure political support for their alternative as well as stimulate interest and possible participation.

## 4. THE MAJOR ECONOMIC ADVANTAGE OF THE TAGS PROJECT IS IN ITS TARGET MARKET--THE PACIFIC RIM

The value of the gas that TAGS would deliver to the Japanese market as LNG is expected to be about 40 percent higher than gas delivered to the Lower 48 states market by ANGTS (about $6.16 per MMBtu for TAGS and $4.04 per MMBtu for ANGTS on average from 1990-2010 in a lower oil price case).

The reason that gas is assumed to be worth more in the Japanese market is that LNG has competed with other LNG import projects on a basis that has in the past been tied to crude oil. Alternatively, natural gas delivered through ANGTS will have to compete with residual fuel oil in the Lower 48 boiler fuel market. Since residual oil is projected to continue to sell at a discount to crude oil, the value of the ANGTS gas is lower than for TAGS.

Accordingly, the projected wellhead value of the TAGS project is higher than that projected for the ANGTS project, as shown in Exhibit I-4. On average, over a 20-year life, the wellhead value for TAGS is $3.21 per MMBtu in Booz, Allen's low oil price scenario, as compared to $1.15 per MMBtu for ANGTS. The wellhead value, which is calculated by subtracting all costs of delivery from the end-use market value, determines the attractiveness of developing the natural gas to a producer. These cost advantages for the TAGS project assume the full scale (three phases) are completed.

In analyzing the wellhead value, several sensitivity cases were developed. As shown in Chapter IV of this report, there are no cases where ANGTS is superior to TAGS from a wellhead value standpoint.

## 5. ALTHOUGH TAGS HAS AN ECONOMIC EDGE OVER ANGTS, QUESTIONS SURROUND ITS MARKETABILITY BECAUSE OF TIMING AND RISK ISSUES

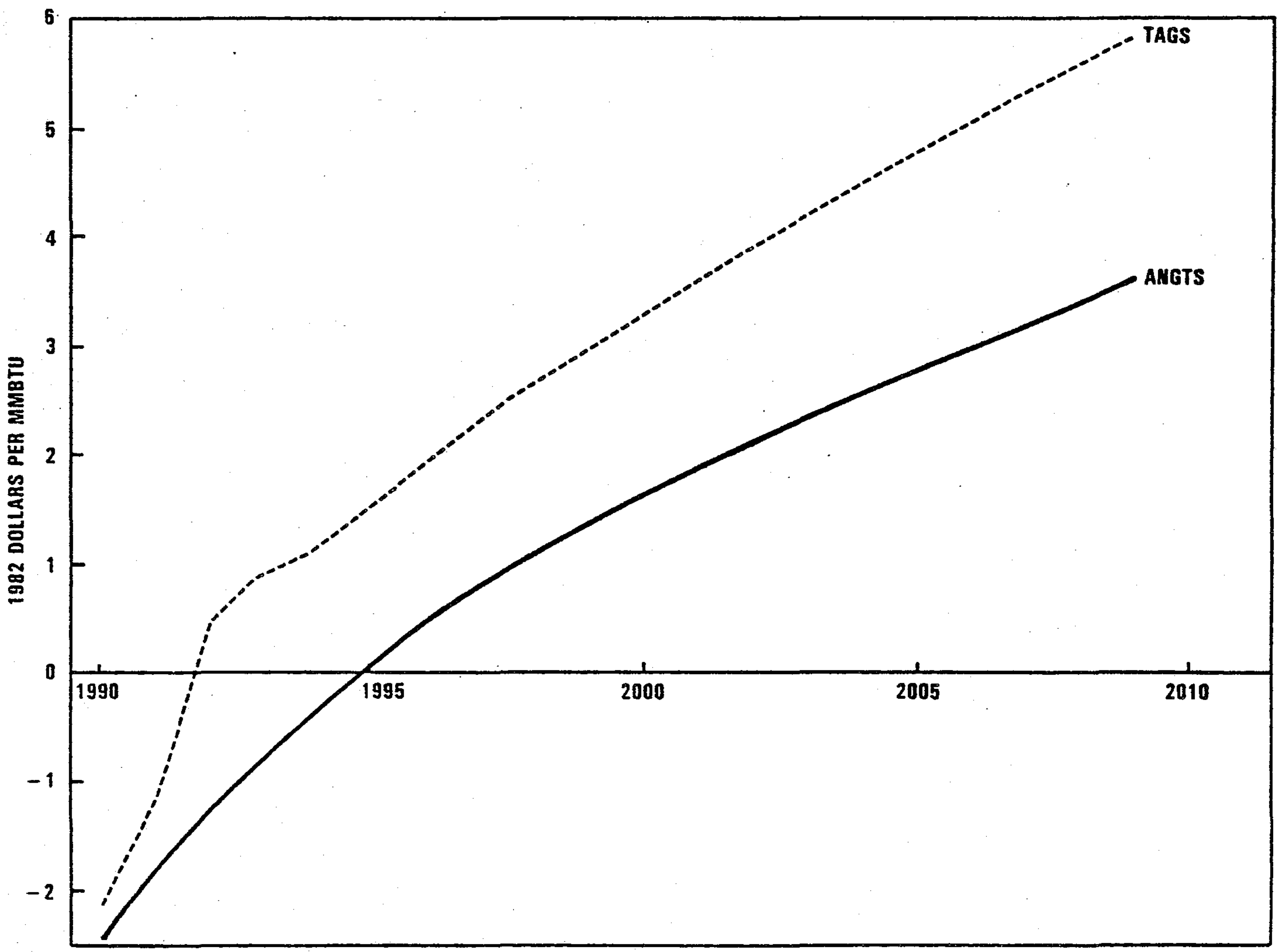
Timing is the key to marketing North Slope gas to Japan via TAGS (and Japan is its key market) because Japan is currently in the process of contracting for LNG supplies it will require during the 1990s. While there is debate over the extent of Japan's LNG shortfall, it seems that there will be a need for additional LNG imports beyond current contract commitments. However, the "window of marketability" in Japan may be closing soon as several projects compete for a somewhat smaller market than originally anticipated. Thus, unless TAGS becomes "the viable project" soon, it may lose its primary market.

This concern about timing is especially relevant since construction of TAGS could be delayed by any one of several factors:

- ANGTS has been the approved route -- and the U.S. the approved market -- for North Slope gas. Even if ANGTS were abandoned (which project sponsors have not done), pre-existing legislation (ANGTA) would need to be modified or repealed to ease the way for TAGS.

Exhibit I-4

NETBACK WELLHEAD GAS VALUE FOR ANGTS AND TAGS
("WEAKER ECONOMY" PRICE CASE)



- The purpose underlying ANGTA was to ease and speed the approval process for construction permits, rights-of-way leasing, and the like, and thus avoid the long delays--and construction escalation--which befell the TAPS line. Absent similar legislation, TAGS may be mired in regulatory delay during construction.

- Presidential authority must be obtained for LNG export of North Slope gas; political sentiment could operate against such approval to the extent that the U.S. remains dependent upon imported oil and domestic gas reserves become more difficult and expensive to replace.

- It may be politically (although not legally) necessary to allow Alaskan oil exports to Japan in order to consummate a major new gas sale to them.

- Gas supply contracts between producers and Lower 48 gas pipelines would need to be cancelled in order to sell North Slope gas production to the TAGS project.

These political and regulatory uncertainties--and potential for delay--could well jeopardize the TAGS concept of Japanese LNG sales. The project advocates state that unless export sales are begun in the 1988-1990 period, the market may be lost until after 2000.

Another key marketability concern is that other sources of LNG for Japan will vie with TAGS. With respect to the ability of TAGS to compete with other LNG projects, in fact, it should be recognized that most other potential LNG suppliers--for example, Canada, Indonesia, Abu Dhabi, Russia, and others--have gas fields located closer and/or more accessible to their export ports than the 820 miles from the North Slope to Kenai. Thus, these countries may have the ability to deliver LNG cheaper than Alaska can, particularly since there are no major transportation distance advantages for marine shipment of LNG.

## 6. GAS-FIRED ELECTRIC GENERATION AT FAIRBANKS IS DESIRABLE, BUT ONLY AS PART OF A MAJOR GAS LINE PROJECT

Building from the work done for the Alaska Power Authority, our analysis shows that using gas for electric generation in Fairbanks is a very attractive option. Under two electric generation scenarios, the economics appear favorable, and electric generation supports infrastructure development around Fairbanks.

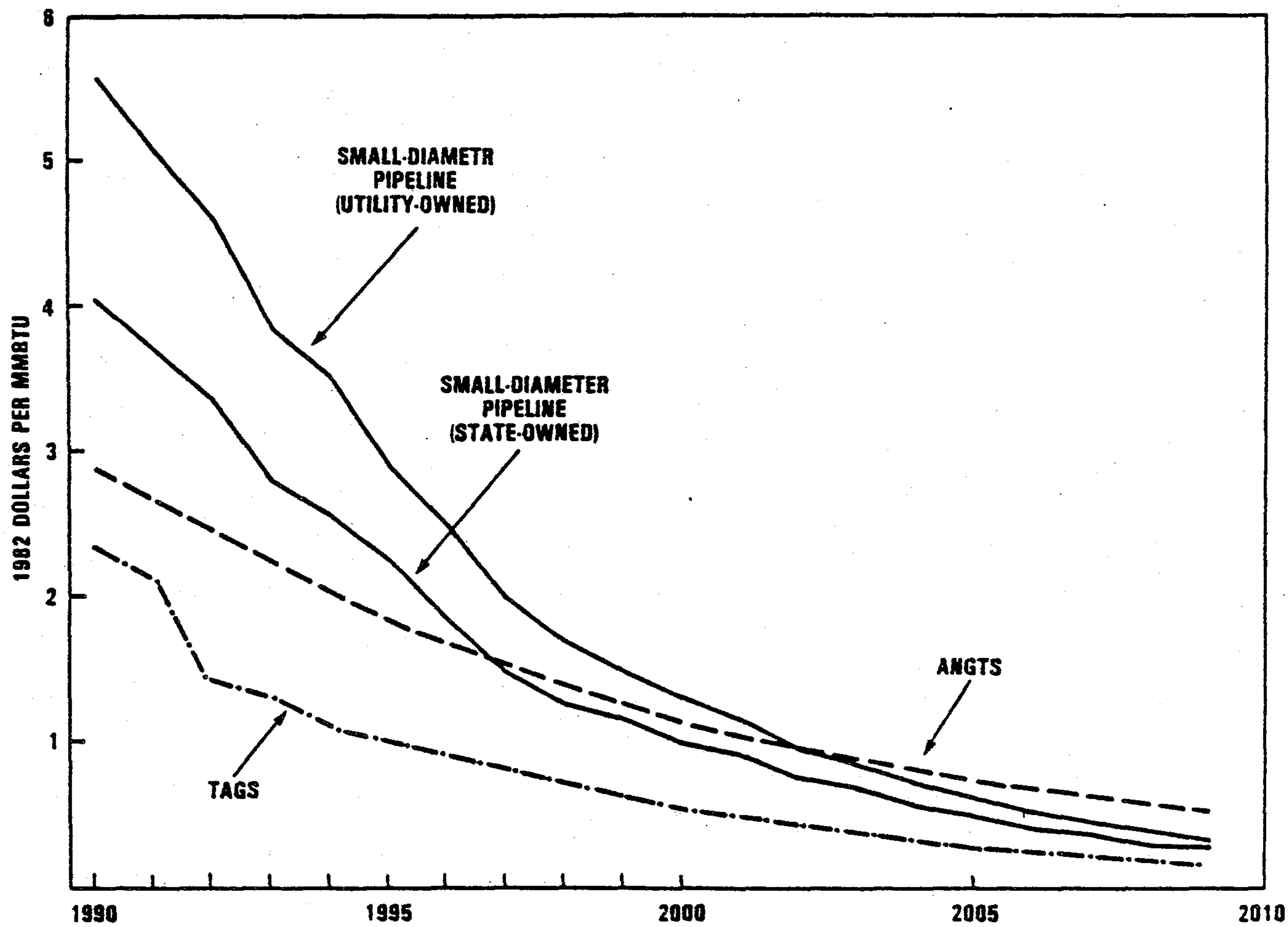
While electric generation appears to be favorable and would enhance the value of North Slope gas, our analysis shows that building a dedicated 480-mile small-diameter pipeline from the North Slope to Fairbanks is not by itself economical compared to tapping off of either TAGS or ANGTS. As shown in Exhibit I-5, the small diameter line requires a significantly higher tariff than tapping either of the major lines. Thus, a small diameter line should be considered only if TAGS or ANGTS faces long delays.

## 7. A METHANOL PLANT AT FAIRBANKS IS ONLY FEASIBLE IF GAS IS TAPPED OFF EITHER THE ANGTS OR TAGS PROJECT, AND IS NOT AS ECONOMIC AS ELECTRICITY GENERATION

A methanol project has been proposed by Alaska Interior Resources, Inc. to transport methanol produced from Fairbanks to Seward via the Alaska Railroad and then sold to Pacific Rim markets. While methanol has a wide variety of

Exhibit I-5

TRANSPORTATION COST FOR GAS DELIVERED TO FAIRBANKS BY TAGS, ANGTS, OR A SMALL-DIAMETER PIPELINE




NOTE: EXCLUDES COST OF GAS USED AS COMPRESSOR FUEL.

applications, the primary market appears to be stationary fuels (boiler fuel) and the competition is crude oil and LNG. Although this proposed project is well-conceived, the per unit operating cost of the methanol plant is about $0.66-$1.09 per MMBtu higher than the electricity plant over the forecast period (35-60 percent higher) as shown on Exhibit I-6. As shown in the exhibit, rail transportation costs of about $0.81 per MMBtu is an appreciable portion of the methanol project costs. Recent efforts of the project sponsors to reduce this rail rate, however, suggest this kind of project can be a viable alternative.

## 8. GAS CAN BE USED FOR EOR ON A TEMPORARY BASIS PRIOR TO THE ONSET OF GAS SALES

At the present time, natural gas and gas liquids associated with North Slope oil production is reinjected. Some analysts have pointed out that partial conversion to hydrocarbon liquids for miscible flood enhanced oil recovery (EOR) constitutes a viable option. In fact, ARCO is initiating experimentation at the Prudhoe Field, Flow Station No. 3 in an effort to determine the degree of oil flow stimulation achievable by injecting an enriched gas and water mixture. This EOR use of gas does not preclude later sale of the same gas, according to ARCO.

At a public meeting held in Anchorage on November 19, 1982, pursuant to ARCO's application to Alaska Oil and Gas Conservation Commission, it was indicated that up to a third of the Sadlerochit field may be amenable to the kind of miscible flooding EOR technique ARCO will be attempting. However, until results from Flow Station 3 become available, no physical or economic data comparable with the other four options in our analysis can be assembled -- including gas use, capital cost, added oil flow rates, operation and maintenance expenses, labor, materials, etc.

## 9. THE STATE WOULD BENEFIT FROM EITHER TAGS OR ANGTS, AND SHOULD HELP FACILITATE BOTH PROJECTS UNTIL MARKET CONSIDERATIONS LEAD TO A SELECTION BETWEEN THEM

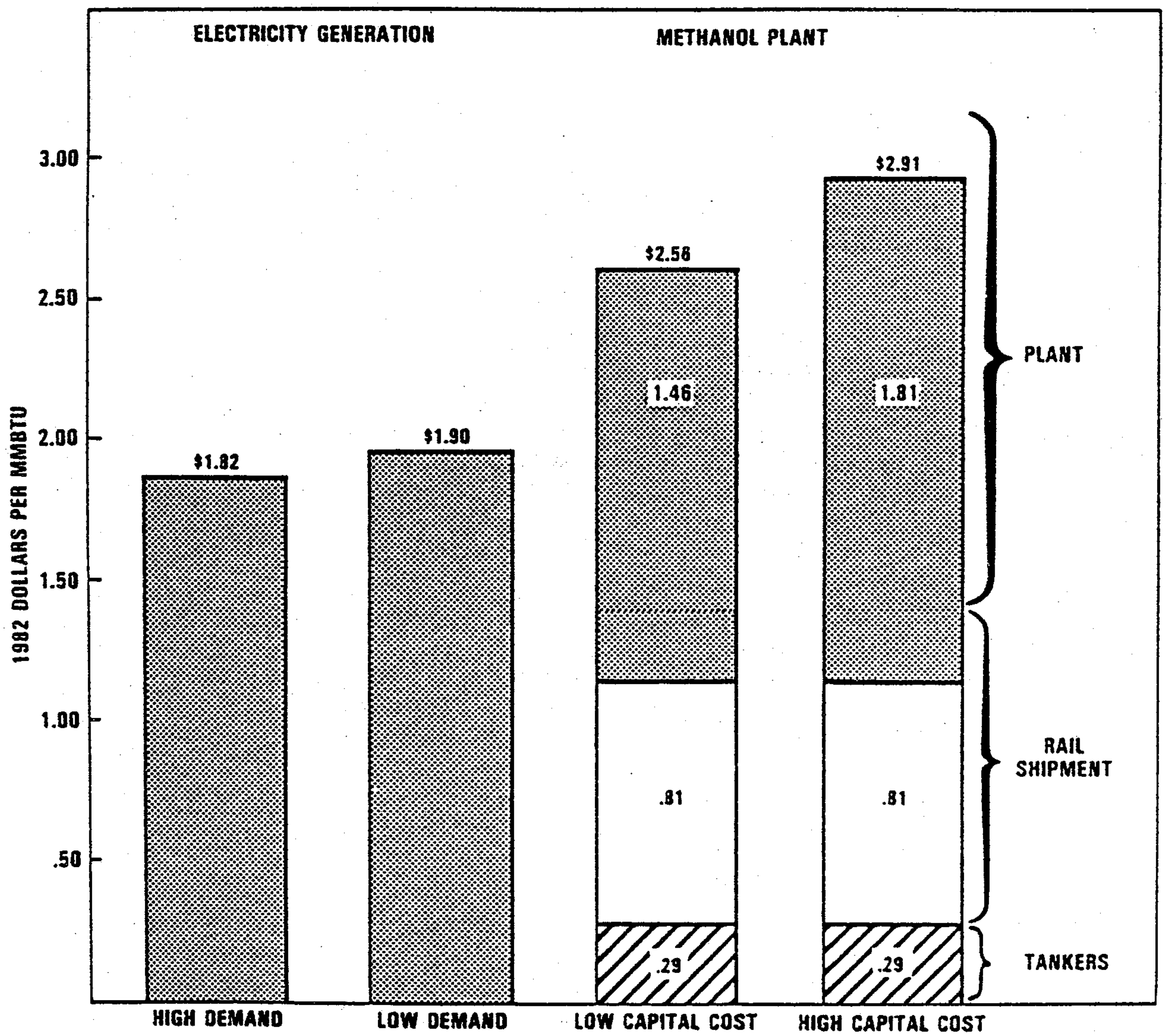
A role for the State of Alaska at this point can be fashioned to facilitate both projects--ANGTS and TAGS--because it is in Alaska's interest to see that North Slope gas is developed. Value-added and royalty payments to the State would be substantial in either case, as would increased employment opportunities for the labor force. Furthermore, from the State's perspective, there is no real difference between TAGS and ANGTS despite their significant economic and marketability differences.

On this basis, it would appear to be in the State's interest to facilitate a marketplace-derived decision between the two by supporting both projects; that is, to support North Slope gas development per se. The gas producers, end-use markets, financial community, and federal government will be deciding factors as to which project, if any, will proceed, based upon economic and market considerations.

In addition, **the State should support a Fairbanks option.** Either the electricity or the methanol option would serve to extend economic development into the Alaskan Interior; thus a spinoff gas project in Fairbanks is in the State's interest. Our economic analysis has concluded that the electrification option is preferred, although there may be a role for both. The State should not argue for either project on a stand-alone basis.

Exhibit I-6

AVERAGE PROJECT COST COMPONENTS FOR METHANOL AND ELECTRICITY GENERATION PLANTS




NOTE: EXCLUDES COST OF GAS FOR FUEL OR FEEDSTOCK.

Finally, the State should recognize that **any decision made now is likely to change as energy markets evolve.** The world energy marketplace--and thereby, the value of North Slope gas and/or its derivatives--has already changed radically several times since the Prudhoe field was discovered fourteen years ago. In addition, even though North Slope gas has been studied before, new transport/end-use options, and new variations on existing options, continue to be developed. An affirmative stand by the State of Alaska on any one option at this time could be upset later for two important reasons:

- Some new options, and new variations on earlier proposals are still being configured particularly since ANGTS announced a two-year delay in 1982. Thus, a precise head-to-head cost comparison (e.g., of steel price assumptions, labor rates) was possible neither at the time, nor within the scope of our study, even for the most promising alternatives.

- World energy markets will not stand still. In fact, recent difficulties by OPEC to attempt to retain control over sliding world crude oil markets may presage some new, important price developments which could change, once again, the economics of all the options we analyzed.

For these reasons, and because the State itself cannot actually select a project, we believe that a role as "neutral facilitator" is most appropriate.

## 10. THERE ARE SEVERAL ADDITIONAL ISSUES THAT SHOULD BE ADDRESSED

In considering the analysis that has been able to be conducted for this study, it appears that there are still some unanswered questions :

- Since the economics of the TAGS project have been developed only recently, additional economic and cost analysis is needed, along with more in-depth comparison with ANGTS

- The Pacific Rim markets appear to be attractive for both LNG and methanol, but timing, competitiveness and market size estimates need to be refined

- The State of Alaska's role, while recommended to be that of a neutral facilitator, should be considered further:

  - What can the State do to facilitate any of these projects?

  - Is there any benefit to support one of the two major projects over the other?

  - What are the State's real objectives with regard to North Slope gas developments?

- What position should the State of Alaska take towards legislative/regulatory issues on gas:

  - Natural gas price deregulation
  - LNG exports
  - ANGTA revisions

- Treatment of TAGS line in Alaska as a gathering system
- Enhanced oil recovery

- The role of the North Slope producers remains unclear. Publicly, all appear committed to ANGTS, but the underlying support needs to be tested further. What, if anything, would cause the producers to switch support to TAGS?

* * * * *

The following chapters of this summary report describe the results of the project evaluation conducted in the course of this study.

- **Chapter II** describes the **study approach** in more detail

- **Chapter III** provides the **end-use market analysis** -- both prospective demand and price of North Slope gas and gas products in the primary markets targeted by each project

- **Chapter IV** presents the **wellhead gas value** projected under each option, based upon the market price forecast and the likely cost of market delivery

- **Chapter V** discusses **in-state benefits** from North Slope gas development, as well as the socio-economic and environmental considerations which must be weighed in selecting a utilization option

- **Chapter VI** describes the financial, legal, regulatory and financial **risks** attendant to each project.

A separate technical appendix volume provides additional detail on the study methodology and assumptions, project cost and operating parameters, and the results of the economic analysis, under "baseline" and sensitivity cases using the cost-of-service pricing model.

## II. INTRODUCTION

With the discovery of the Prudhoe Bay Field in 1968, significant gas reserves -- estimated at 26 Tcf -- were found on the North Slope. Since that time, the economic and regulatory issue has been how best to utilize this resource. Earlier studies of North Slope gas uses included a comprehensive evaluation of alternative systems for transporting the gas to the Lower 48 states. In October 1977, after detailed analysis and debate, Congress approved the Alaskan Natural Gas Transportation System (ANGTS), a 4800-mile pipeline generally following the Alcan Highway across Alaska and Canada to the Midwest and Pacific states. Financial and market uncertainties have delayed ANGTS, and current project planning anticipates construction beginning in 1987, with initial deliveries in January 1990. Thus, nearly six years after passage of ANGTA -- and nearly 14 years after its discovery -- North Slope gas still awaits being brought to market.

Thus, the need has arisen to restudy the broad array of North Slope gas utilization options, and evaluate their economic, financial, technical, regulatory, and social aspects in light of current and prospective economic conditions, energy costs and markets. Reflecting the urgency of such review, two State-sponsored studies have focused on separate Alaska North Slope (ANS) gas utilization options.

- The **Governor's Economic Committee**, headed by former Governors Hickel and Egan, evaluated an intrastate gas system for ultimate transport and sale of North Slope gas as LNG in Pacific Rim markets (known as the "TAGS" project, Trans-Alaska Gas System).

- Under the auspices of the **Alaska Power Authority**, Ebasco is analyzing use of North Slope gas for in-state electricity generation and consumption.

The State Task Force on Alternative Uses of North Slope Natural Gas was convened in 1982 to evaluate potential State backing of ANGTS or other options. The Task Force selected Booz, Allen and Hamilton and its team of subcontractors -- the firms of Homan-McDowell in Juneau, Alaska, and Van Ness, Feldman, Sutcliffe, Curtis and Levenberg, in Washington, D.C. -- to conduct a broad and updated analysis of all the ANS options and their implications. It was recognized that, with the time and resources available, this study could not be at the same level of depth as other studies of specific projects, but rather would compare and evaluate utilization options in light of recent market and economic conditions.

To conduct the study, a wide range of utilization options was narrowed to the most promising alternatives for more intensive evaluation. A large number of transportation and processing alternatives and end-use product markets exist for North Slope gas, as depicted on Exhibit II-1. To properly evaluate the myriad of options, a two-phase approach was employed, as shown on Exhibit II-2, and summarized below.

### 1. IN THE INITIAL STUDY PHASE, POTENTIAL UTILIZATION OPTIONS WERE SCREENED TO IDENTIFY THE MOST PROMISING ALTERNATIVES.

The screening step was designed to narrow a large number of alternative North Slope gas uses to a manageable number for intensive evaluation, while maintaining a

## Exhibit II-1

## EXAMPLE OF OPTIONS FOR USE OF NORTH SLOPE GAS

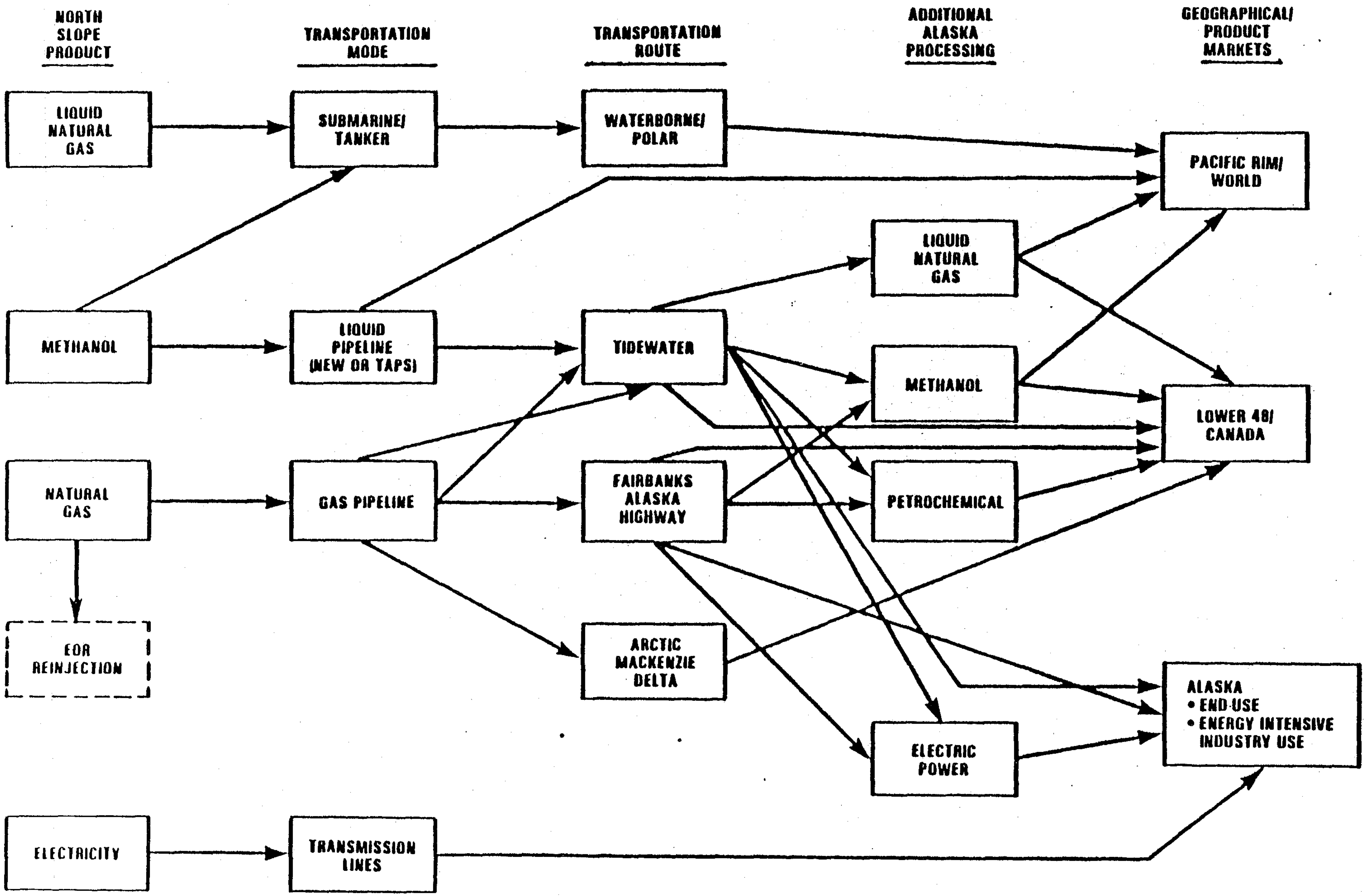
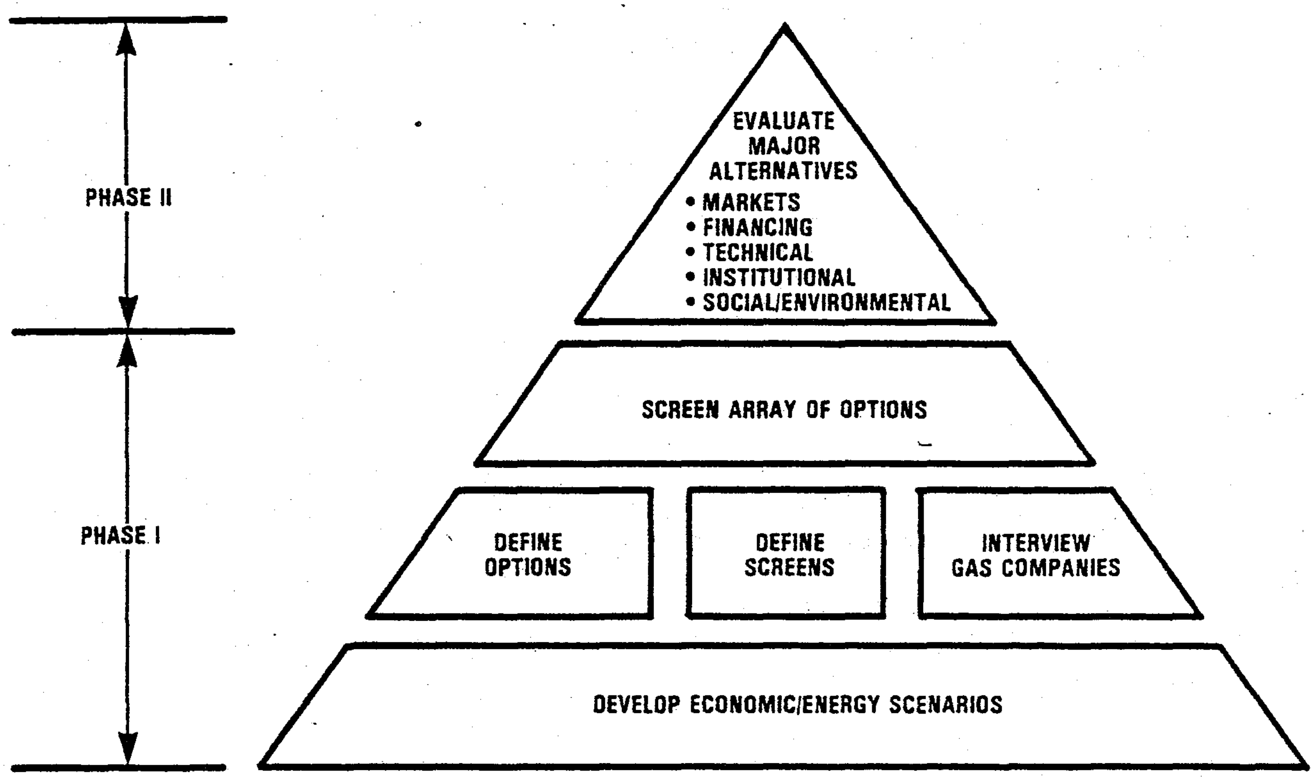


Exhibit II-2

STUDY APPROACH



representative breadth of transportation, market and product options. For this purpose, qualitative and quantitative screening criteria were developed and applied.* Screening criteria included:

- **Economic factors** -- likely value of gas and gas-derived products in end-use markets; the potential netback gas value at the wellhead, derived as the difference between retail price and the cost of product processing/transportation; and State value-added, which reflects economic contributions to the State from project construction and operating expenditures, net State revenues, and employment generated

- **Market factors** -- market size and timing of entry; competitive position of Alaskan gas versus alternative fuels and energy suppliers

- **Risk factors** -- financial uncertainty, both in ability to attract needed capital and to provide return commensurate with risk without foreclosing product marketability; technological risk, or the ability deliver the desired product; legal and political impediments to the project timing, siting and proposed markets

- **Environmental and social concerns** -- the extent to which a project might alleviate -- or exacerbate -- social, environmental and cultural conditions.

These criteria were applied in two screening processes.

- **Minimal survival screening** -- designed to identify substantial risk or technical factors which seriously flaw -- if not preclude -- a particular option, and to eliminate that option from further analysis

- **Comparative screening** -- a relative assessment of projects passing the minimum survival screens, using qualitative evaluation of cost/benefit, degree of risk and similar measures

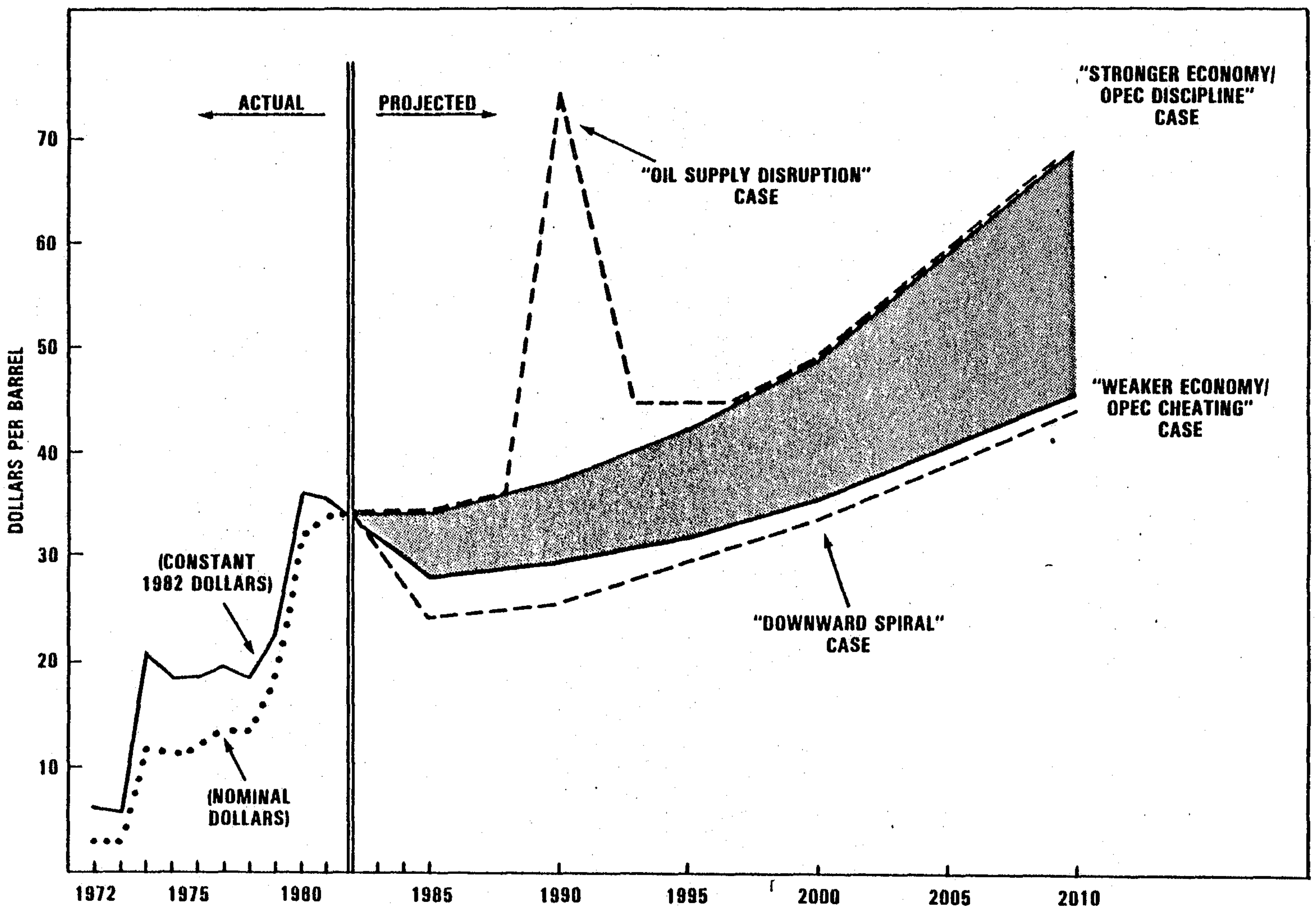
To assess the economic and market characteristics of the various alternatives, four scenarios of future world economic trends and energy supply/demand/price conditions were developed; a distinguishing feature of the scenarios is the crude oil price path assumed by each. These oil price paths serve to drive retail prices for natural gas, petrochemical products, and refined petroleum products which compete with Alaskan natural gas for market share. These prices, in turn, when coupled with economic growth trends implicit within each scenario, set supply and demand levels in the geographic and end-use markets addressable by North Slope gas. For purposes of Phase I screening, a range of oil prices bounded by the two most likely scenarios (denoted by the shaded area on Exhibit II-3) was used to develop product values in the Lower 48, Japanese and Western Europe markets and for Alaskan in-state gas uses.

---

*See Evaluation of Alternatives for Transportation and Utilization of Alaskan North Slope Gas: Phase I Report (November 1982) for a fuller description of the screening criteria and results from this evaluation.

Exhibit II-3

WORLD OIL PRICE OUTLOOK APPLIED IN PHASE I PROJECT SCREENING




SOURCE: PETROLEUM INTELLIGENCE WEEKLY (ACTUAL); BOOZ, ALLEN & HAMILTON INC. (PROJECTED)

2. FROM THE PHASE I ANALYSIS, FIVE OPTIONS WERE SELECTED FOR FURTHER EVALUATION.

As highlighted on Exhibit II-4, the list of options for use of North Slope gas was narrowed to five:

- Conventional gas pipeline to the Lower 48 states, following the Fairbanks/Alcan Highway route (the ANGTS project)

- A high-pressure intrastate gas line carrying raw gas to the Kenai Peninsula, for conditioning and gas liquefaction, with LNG shipment to Pacific Rim markets (the TAGS project)

- Utilizing gas for **electricity generation** in the Fairbanks area, with gas transport provided through either TAGS, ANGTS, or a small-diameter pipeline

- Gas conversion into **methanol** at a plant located near Fairbanks, for eventual sale into Pacific Rim markets; again, transport from the North Slope could be effected by either the TAGS or ANGTS lines (a project proposed by Alaska Interior Resources Co., Inc.)

- Gas use on the North Slope to increase oil flows, such as **enhanced oil recovery (EOR)**, as suggested in ARCO's water/alternated with gas injection proposal recently approved by the State Oil and Gas Conservation Commission.

Salient operating and cost characteristics of the five projects are summarized on Exhibit II-5, while Exhibit II-6 identifies the transport routes and processing sites for these options. The projects selected provide a representative range of transportation, product type, project size and market options. Additionally, the ANGTS and EOR projects provide a benchmark for evaluating all five options; ANGTS constitutes the currently approved project for North Slope gas utilization, while EOR represents an option that does not involve emplacement of facilities for purposes of gas sales.

3. THE FIVE OPTIONS SELECTED THROUGH PHASE 1 SCREENING WERE EVALUATED MORE INTENSIVELY IN PHASE 2.

In Phase 2, the economic feasibility, cost/benefit/risk characteristics, and other externalities associated with each project were analyzed in greater depth.

The major elements of the economic evaluation include:

- **End-use market price.** Building upon the energy/economic scenarios developed in Phase 1, the prospective retail price for Alaskan gas and gas products in the geographic and end-use markets targeted by each project was forecast. The price projections explicitly recognized:

  - The need for Alaskan gas to be competitively priced with alternative fuels and supply sources

  - Uncertainty as to future price levels and price direction for natural gas and competing fuels.

Exhibit II-4

NORTH SLOPE GAS OPTIONS SELECTED FOR STUDY EVALUATION

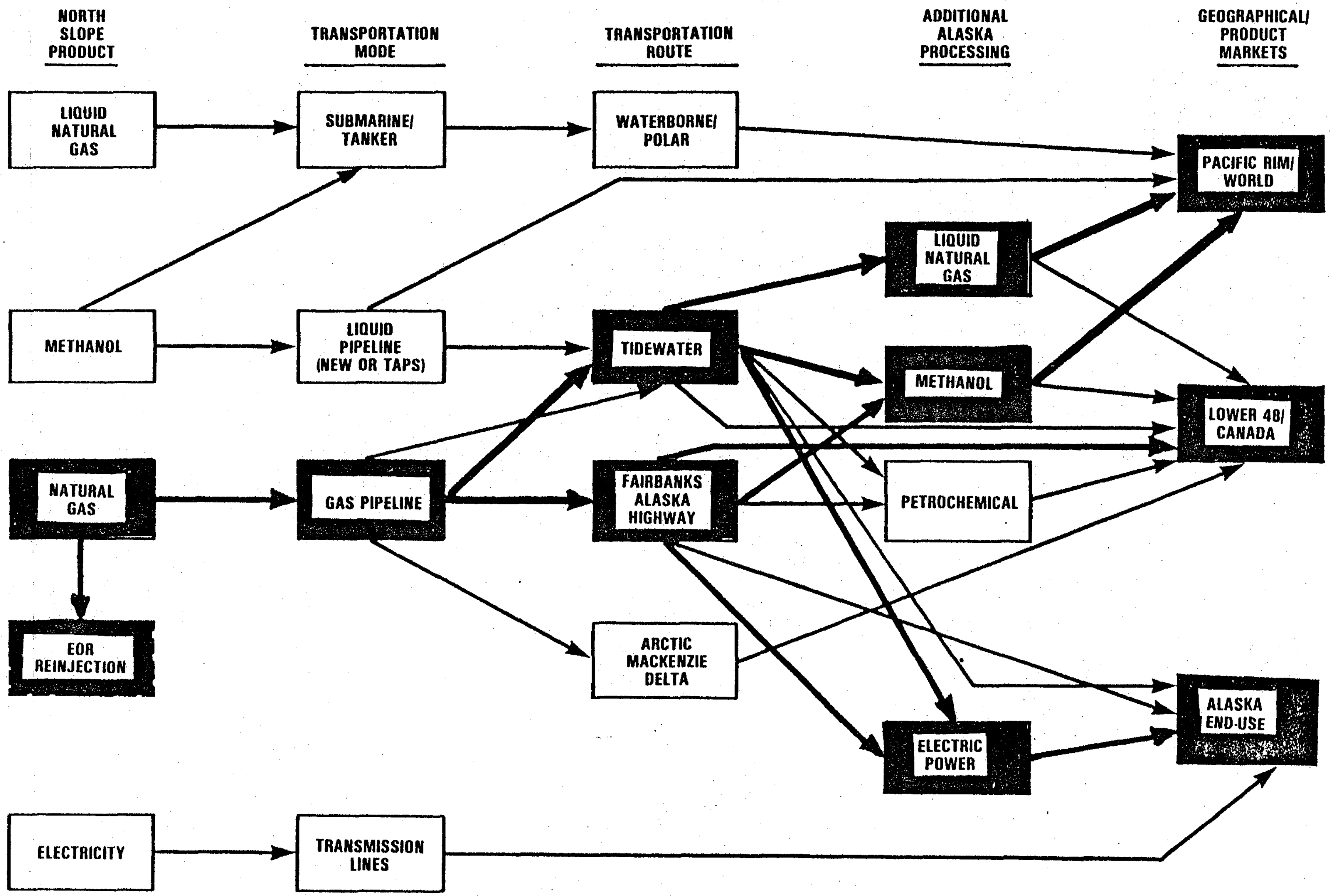


Exhibit II-5

## SALIENT CHARACTERISTICS OF PROJECTS SELECTED

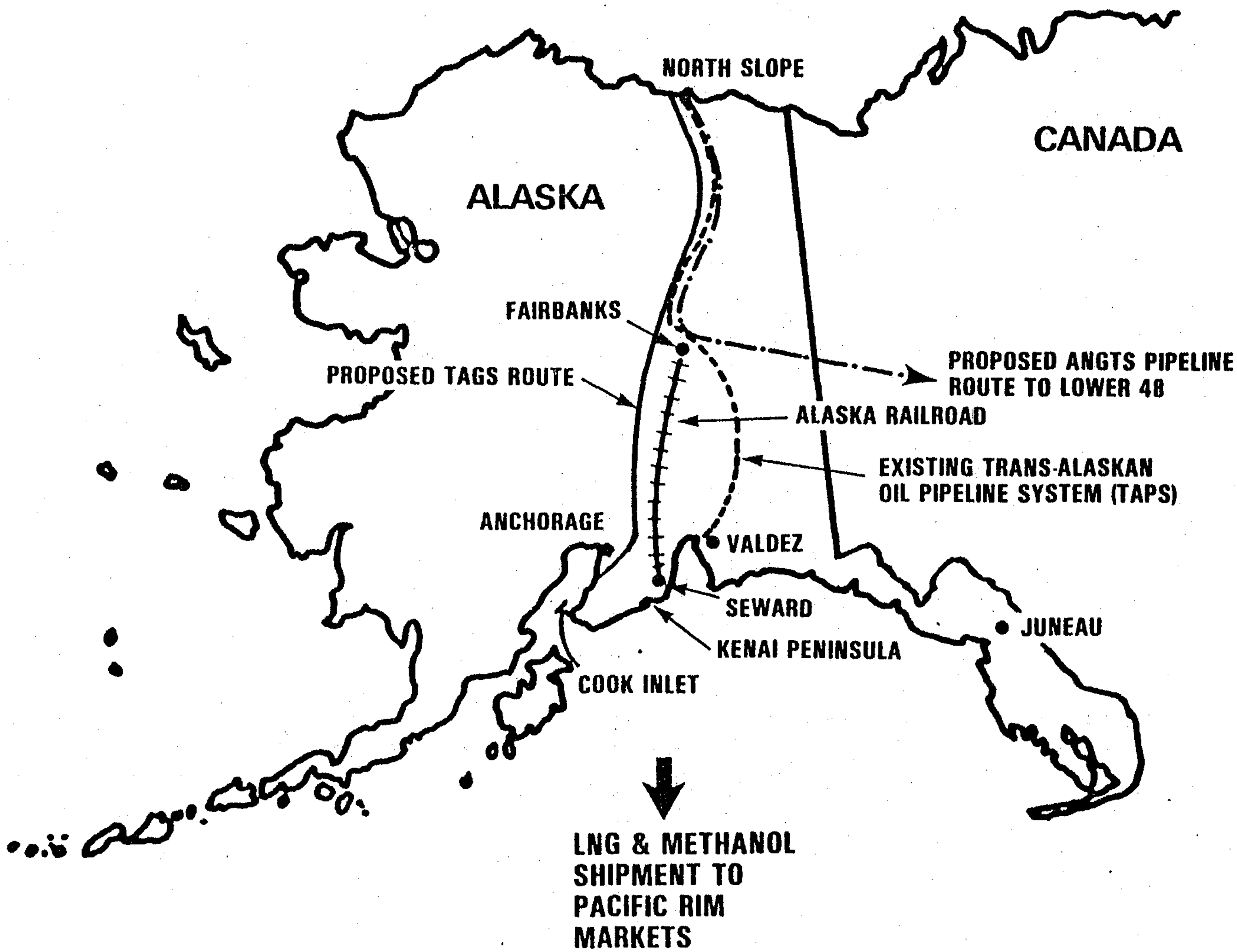
| PROPOSED PROJECT | ESTIMATED CAPITAL COST[1] (MIL. 1982 DOLLARS) | GAS REQUIREMENTS (BCF/YEAR) | MAJOR PROJECT COMPONENTS | MAJOR PRODUCT(S) | MAJOR MARKET(S) |
|---|---|---|---|---|---|
| ALASKAN NATURAL GAS TRANSPORTATION SYSTEM (ANGTS) | $23.488[4] | 766.5 | 4800-MILE PIPELINE (730 MILES IN ALASKA); NORTH SLOPE GAS CONDITIONING PLANT | NATURAL GAS | LOWER 48 STATES |
| TRANS-ALASKA GAS SYSTEM (TAGS) | $14,294[2] | 346.75[3] (PHASE I); 1032.95[3] (FULL SYSTEM) | 820-MILE ALASKAN PIPELINE; GAS CONDITIONING AND LIQUEFACTION PLANT ON KENAI PENINSULA | LNG NATURAL GAS LIQUIDS (NGLs) | JAPAN; OTHER PACIFIC RIM |
| METHANOL PLANT | $575-$725 | 50.0 | METHANOL PLANT; ELECTRICITY CO-GENERATION PLANT (125 MW) AT FAIRBANKS | METHANOL ELECTRICITY | JAPAN; OTHER PACIFIC RIM; FAIRBANKS |
| ELECTRICITY GENERATING STATIONS | $590-$1121 | 4.5 INITIALLY, RISING TO 38-73 | GENERATING STATIONS AT FAIRBANKS (726-1386 MW); HIGH-VOLTAGE TRANSMISSION LINE THROUGH RAILBELT | ELECTRICITY | ALASKA RAILBELT |
| ENHANCED OIL RECOVERY (EOR) | UNKNOWN | 800 (EST'D) | NORTH SLOPE GAS TREATMENT FACILITY; REINJECTION WELLS | OIL | U.S. WEST & GULF COASTS |

SOURCES: NORTHWEST ALASKA PIPELINE (ANGTS); REPORT OF THE GOVERNOR'S ECONOMIC COMMITTEE (TAGS); ALASKA INTERIOR RESOURCES, INC. (METHANOL); APA/EBASCO (ELECTRICITY); ARCO (EOR)

FOOTNOTES:
1. EXCLUDES FINANCING COSTS.
2. FOR FULL SYSTEM.
3. RAW GAS (INCLUDES 12.5% $CO_2$, AND ASSOCIATED NGLs).
4. INCLUDES "PRE-BUILT" SYSTEM COSTS.

Exhibit II-6

PROPOSED PROJECT SITES AND TRANSPORTATION ROUTES



- **Netback wellhead price.** Using project capital cost and operating parameters supplied by the project sponsors, augmented with outside studies, the cost of delivering Alaskan gas and gas products to the target markets was determined. These costs were annualized using a cost-of-service pricing model common to public utility-type projects. Subtracting the processing/transportation cost from the projected retail market price -- after allowance for gas losses (e.g., compressor fuel use, process conversion efficiency, etc.) -- yields the value of the gas at the wellhead. This value necessarily changes over time, due to

  - Changing marketplace retail prices

  - Declining transportation/processing changes (whether expressed in real or nominal dollars) resulting from a cost-of-service pricing methodology.

- **State Value-Added.** To quantify the value to the State of Alaska from the alternatives proposing to utilize the North Slope gas resource, the income stream provided by each project was estimated and summed over a 20-year operating period. A twenty-year period, terminating in 2009, was applied for purposes of comparability.* The revenues considered were:

  - Local property taxes

  - State corporate income taxes

  - Severance tax payments

  - Gas royalty payments, or the value of payment in-kind in the case of two Fairbanks-based projects which would utilize the State's royalty interest gas.**

  This revenue stream varies by project, based upon

  - Amount and value of gas used (affecting the royalty, severance and income tax payments)

  - Project capital cost (affecting both property and income tax amounts).

  To better reflect the impact from revenue stream variations over time, State revenues were discounted back to 1982, using the State's assumed cost of capital (i.e., 10.5% nominal, 3.5% real).

---

*However, for the electricity generating option, a shorter period (14 to 17 years teminating in 2010) was used, reflecting capacity addition plans.

**The electricity generation option, presumed owned and operated by APA, pays no income tax (although payments are made to the Borough in lieu of property taxes at a level equal to the property tax rate). This option makes interest payments (assumed at 10.5% nominal, 3.5% real); if financed through state revenues -- rather than a public debt offering -- such payments could accrue to the State rather than to the bondholders.

For the economic analysis, reasonable project costs and operating parameters were used as baseline comparisons, within a range of "most likely" retail prices for the primary target market. However, sensitivity tests were conducted by

- Evaluating alternative end-use markets and different price scenarios
- Varying project construction costs and costs of capital
- Examining alternative project timing and sizing options.

All of these factors, in combination with the results of the project economic analysis, led to the assessment summarized in this report.

To complete the Phase 2 analysis, project risk and socio-economic and environmental impacts were analyzed. Risk analysis focused on factors affecting project economic feasibility, such as:

- Legal and regulatory risks
- Political risks
- Market entry and competition
- Technology.

Other project externalities evaluated included:

- Environmental impacts and concerns
- Contribution to -- or strain upon -- state infrastructure
- Employment benefits, both direct and indirect.

# III. END-USE MARKET ANALYSIS

This chapter analyzes the end-use markets for Alaskan North Slope gas as targeted by the five projects under consideration. These market assessments -- which build upon analysis conducted in the Phase I study -- are a key element in evaluating the economic feasibility of the five projects. The end-use market assessments are designed to:

- Quantify the likely range of delivered prices required for Alaskan gas and gas-derived products to be competitive with alternative fuels and fuel suppliers
- Identify the prospective level of product demand and timing of demand.

These market factors, in turn, ultimately drive the timing, sizing and pricing of North Slope gas production and thereby determine prospective state revenues from the gas resource.

Exhibit III-1 arrays the target markets for each project by geographic location and end-use application. Excepting in-state gas use for electricity generation, market prices for North Slope gas are determined to a significant degree by world oil prices. Recognizing the uncertainty attendant to any forecast of world prices, a set of price scenarios were constructed to bracket a broad range of plausible future outcomes. The following sections of this chapter summarize:

- The oil price scenarios developed, and the key assumptions used to derive the world energy and oil outlook
- Energy market conditions -- including retail prices developed for the gas netback price determination -- in the primary target markets for North Slope gas and gas-derived products
- Implications on market entry strategy and timing from the competitive structure and pressures implied by each scenario.

Additional detail on the methodology and assumptions underlying the product market assessments has been provided in an accompanying technical report.

## 1. AS A FOUNDATION FOR THE MARKET ASSESSMENTS, FIVE CRUDE OIL PRICE PATHS WERE PROJECTED, WHICH BRACKET A BROAD RANGE FUTURE WORLD OIL CONDITIONS

As will be explained in greater detail in the following section, world oil price levels serve to determine energy market conditions for all fuels -- including natural gas and gas-derived products. Therefore, for its Phase I screening analysis, Booz, Allen constructed four scenarios for future world oil price levels, depicted on Exhibit III-2. Key drivers within each scenario include

- Magnitude and timing of world economic growth
- Volume of OPEC-produced oil needed to meet Free World oil demand
- The level of OPEC productive capacity and degree of capacity utilization

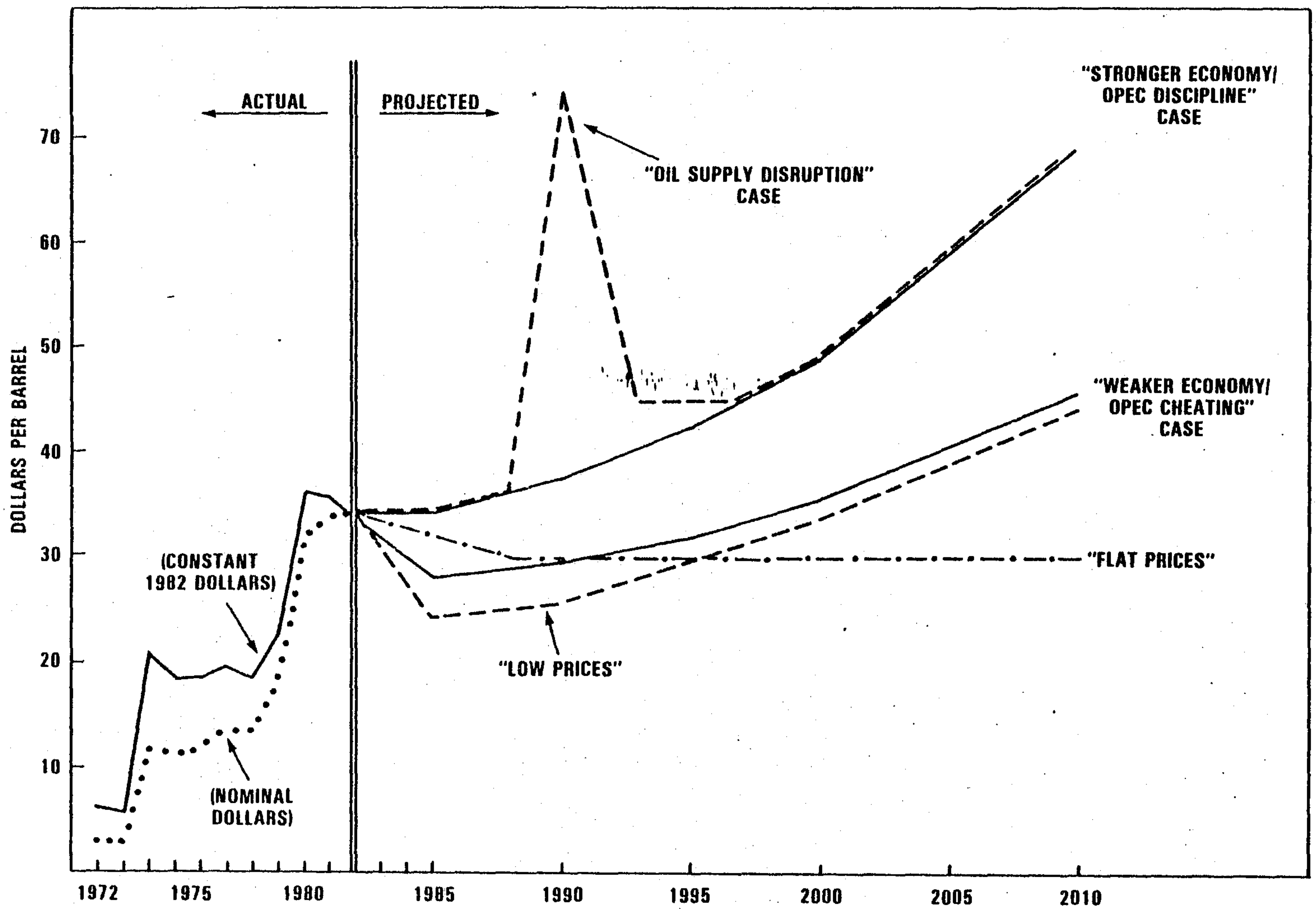
Exhibit III-1

END-USE MARKETS TARGETED BY NORTH SLOPE GAS PROJECTS

| PROJECT | TARGET MARKET(S) | | COMPETITION | |
|---|---|---|---|---|
| | GEOGRAPHIC | END-USERS | PRICE | SUPPLIERS |
| ANGTS | LOWER 48 STATES (WEST COAST; MIDWEST & MID-ATLANTIC) | TRADITIONAL GAS USERS (RESIDENTIAL, COMMERCIAL, INDUSTRIAL, ELECTRIC UTILITY) | PRICED AGAINST INDUSTRIAL RESIDUAL FUEL OIL AT BURNERTIP | DOMESTIC PRODUCERS: OVERLAND IMPORTS FROM CANADA & MEXICO |
| TAGS | JAPAN (PRIMARY); KOREA, TAIWAN, U.S. WEST COAST (SECONDARY) | ELECTRIC UTILITIES (PACIFIC RIM MKTS); TRADITIONAL END-USERS (U.S. WEST COAST) | PRICED AGAINST CRUDE IMPORTS IN PACIFIC RIM | PROPOSED NEW LNG IMPORTS (JAPAN) |
| FAIRBANKS/ METHANOL | JAPAN (PRIMARY); U.S. WEST COAST (SECONDARY) | ELECTRIC UTILITIES (PRIMARY); TRANSPORTATION FUEL & CHEMICAL MKTS (SECONDARY) | PRICED AGAINST CRUDE OIL/LNG | PROPOSED NEW LNG IMPORTS (JAPAN) |
| FAIRBANKS/ ELECTRICITY GENERATION | ALASKA "RAILBELT" | TRADITIONAL ELECTRICITY USERS (RESIDENTIAL, COMMERCIAL, INDUSTRIAL) | PRICED AGAINST HYDRO-GENERATED ELECTRICITY | SUSITNA |
| NORTH SLOPE EOR | LOWER 48 (GULF & WEST COAST) | REFINERIES | PRICED AGAINST CRUDE IMPORTS, LANDED AT GULF COAST | DOMESTIC & FOREIGN PRODUCERS |

Exhibit III-2

PROJECTED WORLD OIL PRICES




SOURCE: PETROLEUM INTELLIGENCE WEEKLY (ACTUAL); BOOZ, ALLEN & HAMILTON INC. (PROJECTED)

The price levels resulting from each scenario embody different assumptions concerning world economic trends and the stability of world oil markets. The two "more likely" scenarios assume no major shocks in the oil markets.

- The **stronger economy/OPEC discipline** scenario assumes world economic recovery beginning in 1983-84, coupled with OPEC discipline on oil supplies and prices

- The **weaker economy/OPEC cheating** scenario assumes economic recovery delayed to the mid-1980's, and near-term inability on the part of Saudi Arabia to enforce production ceilings and official prices.

Two other scenarios are considered less likely to occur, and would not drastically alter the price of crude oil in the long-term:

- A significant interruption of OPEC oil supplies (**oil supply disruption**); 1989 is shown for illustrative purposes only, since the precise timing of a disruption cannot be predicted. The resulting economic effects and sharp fall-off in demand, coupled with restoration of oil producing capacity, eventually forces price reductions.*

- A persistent reduction in oil demand leading to widespread OPEC disagreement on production ceilings and tumbling spot market prices for oil (**low price****). While this scenario seems more plausible as this report is being written, its impact in the long-term -- the period most relevant to this study -- is minimal. This is because low prices and low demand retards non-OPEC oil reserve development; thus, when economic growth resumes in the early 1990's, oil prices move relatively rapidly to convergence with the "weaker economy" price level.

A fifth price path was posited in the recent report of the Governor's Economic Committee, and is labeled on Exhibit III-2 as **flat prices**; this energy market scenario reflects a 2%/year real decline in world prices to 1988, and no increase in real terms thereafter. While the interaction of economic conditions and oil supply/demand forces could force prices above the level expressed in the "flat prices" trajectory, the recent inability of OPEC to limit production and thereby bolster its pricing regime does support the credibility of a "flat price" scenario.

---

*While the exhibit depicts the impact of a supply disruption in the "stronger economy/OPEC discipline" scenario, a price spike of similar magnitude could be applied to either of the other two scenarios. While the "disruption" scenario depicts prices returning to the pre-disruption trajectory, the combination of (a) significant and persistent oil demand reduction, (b) greater non-OPEC supplies elicited by higher prices, and (c) complete return of OPEC producing capacity, could even force prices below the pre-disruption price path.

**This price scenario was originally labeled "downward spiral" in the Phase 1 report; the change in nomenclature was for the sake of clarity and is not a revision in the underlying assumptions of this scenario.

In assessing the feasibility -- and netback gas value -- of alternative uses of North Slope gas, all five price paths were considered. For purposes of this summary report, the results obtained under the "weaker economy," "stronger economy" and "flat prices" scenarios have been emphasized.

2. TO SUCCESSFULLY PENETRATE THE TARGET MARKETS, NORTH SLOPE GAS AND GAS PRODUCTS MUST BE PRICE-COMPETITIVE WITH ALTERNATIVE FUELS AND SUPPLY SOURCES

From the energy/economic conditions implied by the two "most likely" Booz, Allen scenarios and the "flat price" scenario, an assessment of market size and end-use product value can be undertaken in the two key markets for North Slope gas and gas-derived products:

- **Lower 48 states** -- for natural gas
- **Japan** -- for LNG and methanol deliveries.

The third market using North Slope gas -- **in-state electricity generation** -- has been appraised independently in a study commissioned by the Alaska Power Authority; both market size and product value is therefore not directly linked with the scenarios developed for this study purpose.

Set out below is an analysis of each of the three end-use markets with respect to likely retail price and market demand. Concluding this section is a discussion of prospective market and wellhead prices for North Slope crude oil, used in evaluating the economics of gas use for enhanced oil recovery.

**(1) In Lower 48 markets, North Slope gas must be competitive in the large-volume end-user market**

Alaskan gas, delivered through the ANGTS pipeline is destined for two discrete geographic areas

- **West of the Rockies**
- **East of the Rockies,** primarily the Midwest and Mid-Atlantic regions.

In both areas, however, the most likely end-use markets for North Slope gas are the traditional stationary use applications; i.e., residential, commercial, industrial, and to a lesser extent, electric utilities. The most price sensitive of these sectors is the large-volume industrial and electric utility market. With currently-installed dual-fuel firing capability, some 20-25% of current gas usage -- or nearly 4 Tcf -- is at risk if natural gas prices substantially exceed residual fuel oil (No. 6 oil) at the burner tip. The potential for fuel-switching is likely to grow in the future, thereby increasing the need for gas to be competitive with residual fuel oil prices.

Accordingly, the key determinant of future retail gas prices is the price of residual fuel oil, which in turn is largely determined by the price of world crude oil. In the absence of market disequilibrium, residual fuel oil has historically sold at a discount to crude oil, while other higher-value refined products (e.g., gasoline, distillate and jet fuel) sell at a premium to reflect market willingness to pay and the cost of refining. While residual fuel oil currently sells at 80-90% of the refiners crude acquisition cost, this discount could increase in the future due to softening demand for oil products and growing world supplies of residual fuel resulting from the changing nature of world crude supplies. The competitive -- or market cleaning -- price of natural gas under the three price scenarios depicted on Exhibit III-3 for the Lower 48 states incorporates lower refinery margins on resid (75-80% of refiners crude acquisition cost). There may be slight regional variations from this price path.

- Along the U.S. **Atlantic coast**, resid prices tend to be lower than the national average, reflecting importation of large volumes of Caribbean-produced resid and availability of lower-cost water-borne transport of resid

- Resid prices in the **Midwest** tend to be slightly higher than the national average, largely reflecting the cost of crude transport to local refineries

- In **West Coast** markets, the lower cost of crude oil feedstock (deliveries of North Slope-produced crude) is largely offset by stringent environmental regulations, requiring consumption of much higher quality residual fuel oil -- 0.25% sulfur, in contrast to an average sulfur content of 1.0-2.0% in Midwest and Mid-Atlantic markets. These higher refining costs (whether for desulfurization or refiner purchase of "sweet" crude) results in quality-compliant resid prices which exceed the national -- and Mid-Atlantic region -- average.

In determining which of the three geographic markets would be the price-setter for Alaskan gas, the analysis considered:

- The relative importance of gas sales to large-volume end-users

- The existing gas supply slate and prices for pipelines serving each region

- The distribution margins on large-volume end-user sales imposed by local gas distributors

- The burner-tip price of residual fuel oil.

All three regions are heavily dependent on industrial and electric utility sales, as shown on Exhibit III-4. In California -- which dominates West Coast gas markets -- a substantial portion of large end-user gas sales are to electric utilities, where gas (along with oil) is used as a "swing" fuel to balance electricity generation demands with availability of hydroelectricity. Exhibit III-5 compares the regional retail gas price to large-volume customers with the price of residual fuel oil. Resid prices are shown in a range; the upper end is the actual price paid by electric utilities while the lower end is the price estimated by the FERC for industrial and utility purchasers.* The exhibit shows that, on average, resid prices are lower in

---

*The FERC price estimate -- used in applying the incremental pricing provisions of the NGPA -- is set at two standard deviations below the average price of high sulfur resid sold in the state or region. It does not, therefore, necessarily reflect the prevailing price, or the price set on residual fuel oil of a quality which complies with environmental standards.

Exhibit III-3

PROJECTED RETAIL PRICE OF NATURAL GAS AT "MARKET CLEARING" PRICE LEVELS IN LOWER 48 MARKETS

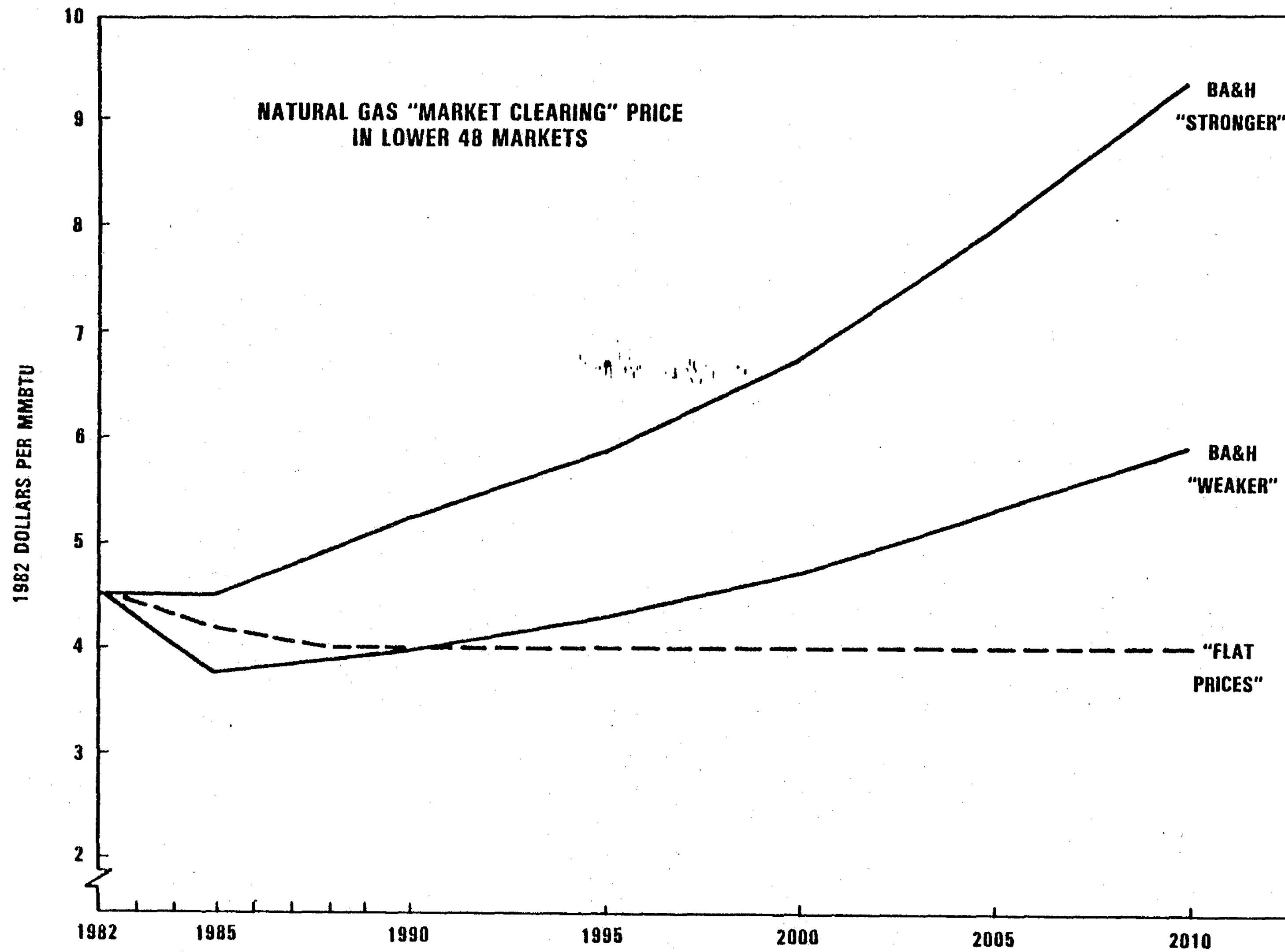
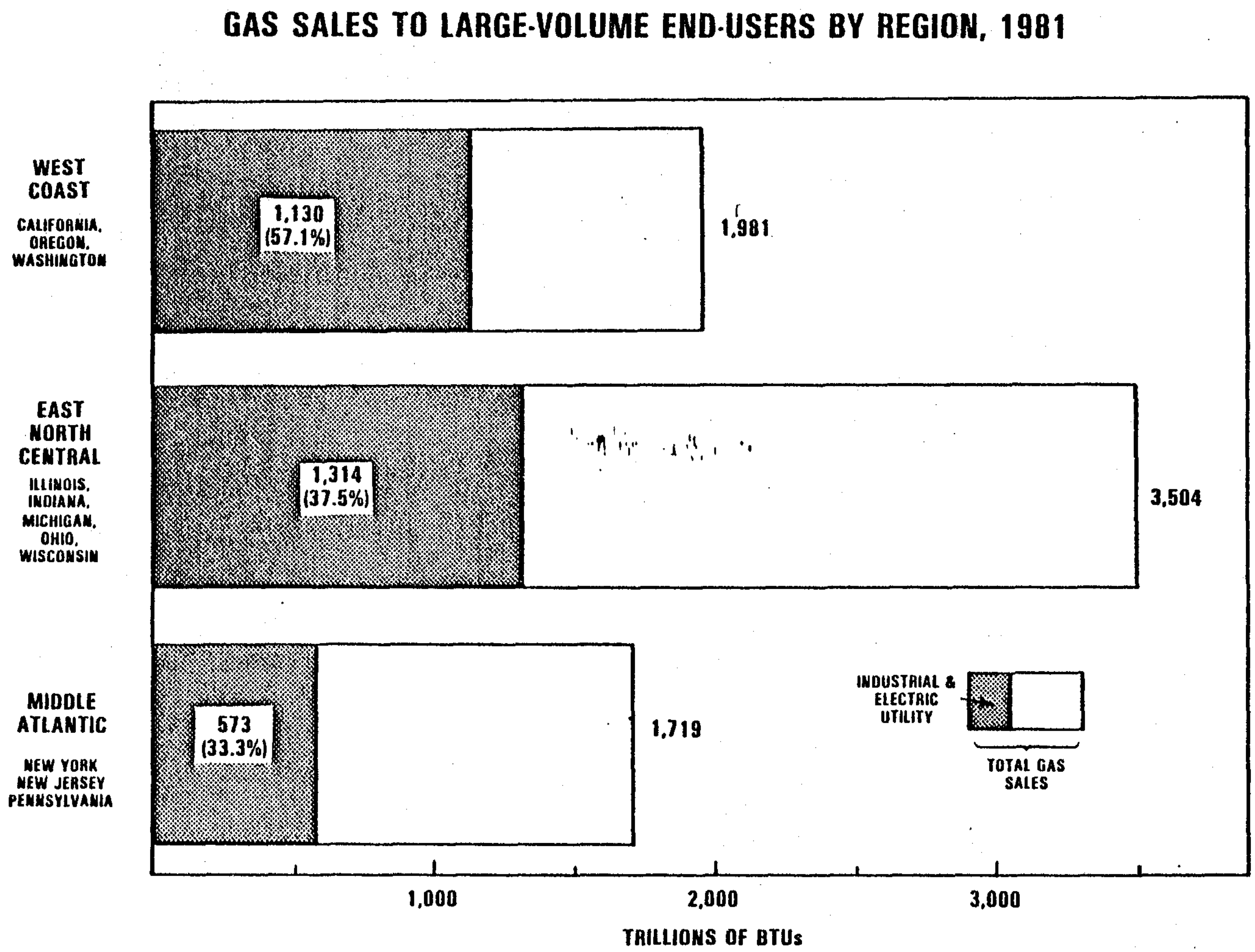


Exhibit III-4

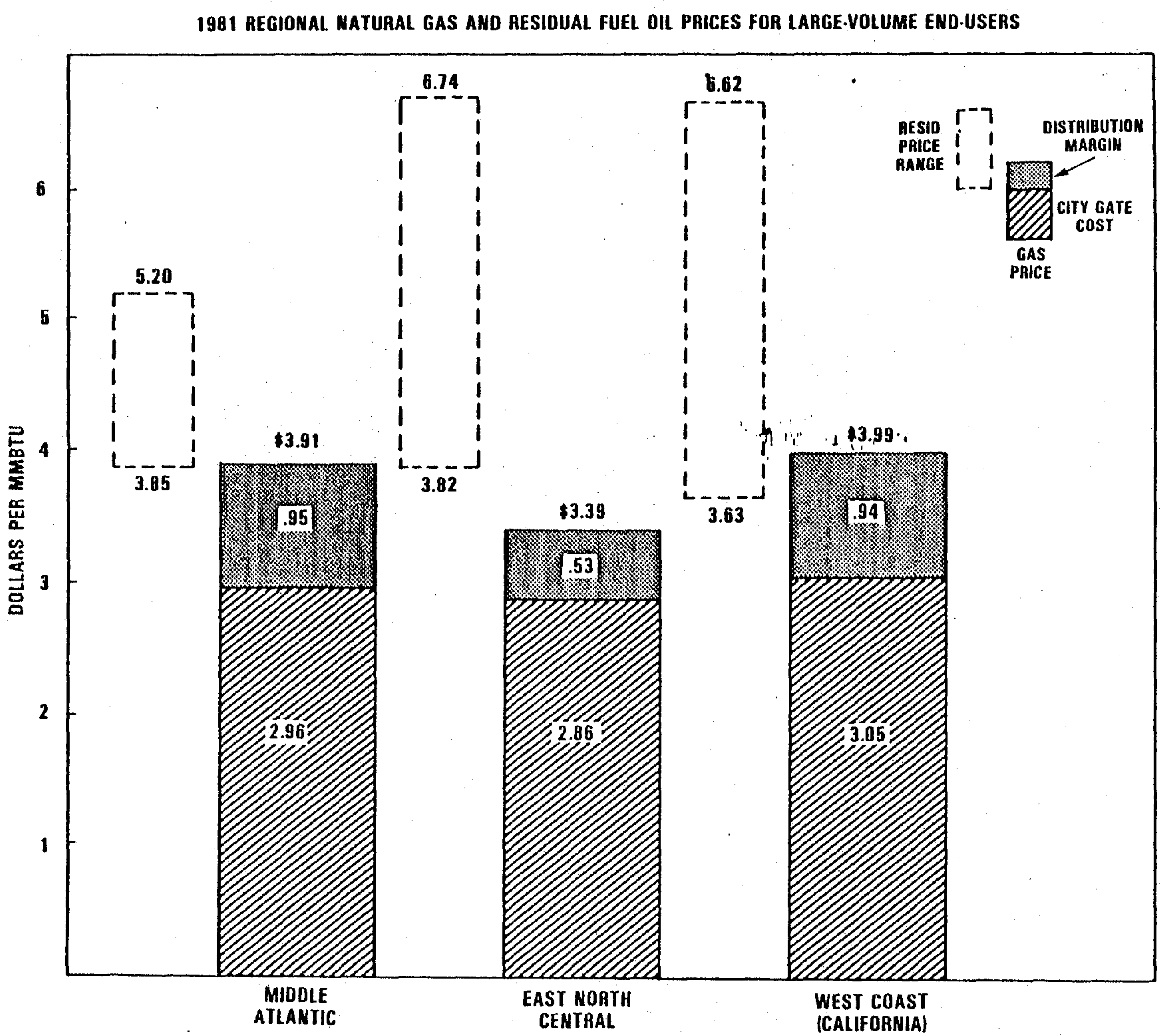
1981 GAS SALES TO LARGE-VOLUME CUSTOMERS BY REGION

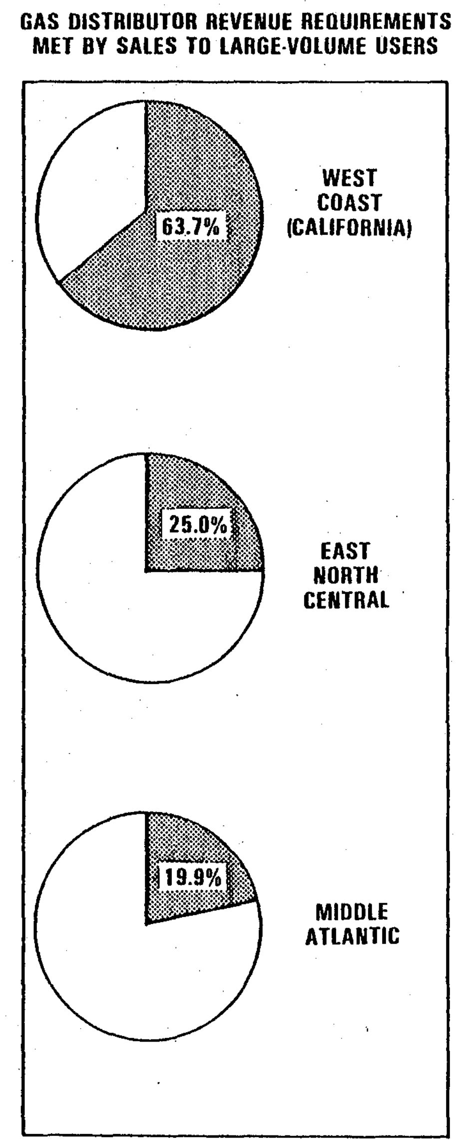



SOURCE: AMERICAN GAS ASSOCIATION, GAS FACTS, 1981.

Exhibit III-5

PRICING FACTORS IN LARGE-VOLUME GAS SALES BY REGION




SOURCE: AMERICAN GAS ASSOCIATION, GAS FACTS, 1981 (DECEMBER 1982); U.S. DEPARTMENT OF ENERGY, COST AND QUALITY OF FUELS FOR ELECTRIC UTILITY PLANTS, 1981 ANNUAL (SEPT. 1982); FEDERAL ENERGY REGULATORY COMMISSION, DECEMBER 1981.

the Mid-Atlantic region, while large-volume gas prices are among the highest -- suggesting that this region could serve as the marginal market for Alaskan gas and thus the price setter.

This premise is further strengthened by examining distribution margins on large-volume sales. Both the Mid-Atlantic and West Coast (primarily California) margins are comparable; however, the California Public Utility Commission's policy has been to impose a disproportionate share of utility operating costs on large-volume customers, as shown on the right hand side of Exhibit III-5. This policy was practical while price regulation held domestic gas prices below the market clearing price (i.e., priced against resid netted back to the field). With sharply rising gas prices beginning in late 1982 and early 1983, however, market pressures have begun to force a change in this pricing policy. If distribution margins for large-volume California gas users reflected cost-of-service allocations prevailing in the Midwest or Mid-Atlantic regions, then the 1981 margin of 94¢ would drop to 56¢ -- resulting in a retail price of $3.61/MMBtu.

On this basis, the Mid-Atlantic market appears most likely to be the price setter, having the lowest competitive retail price and the highest industrial customer distribution margin. Accordingly, this market was used for determining the netback value of Alaskan gas deliveries.

At a price which is competitive with alternative fuels and other incremental sources of gas supplies, there should exist a market for Alaskan gas deliveries in the Lower 48 states. As shown on Exhibit III-6, expectations as to conventional domestic gas production fall within a narrow band, with new discoveries becoming an increasing share of domestic production. Presuming relatively flat domestic gas demand -- or even a slight decline -- the need for supplemental supplies -- including Alaskan gas -- is evident. Nonetheless, this market is not assured.

- Mexican and Canadian export pricing policies may be modified to reflect softer U.S. gas markets, and thus try to underprice Alaskan gas.

- Without certainty of receipt of Alaskan gas, potential purchasers may contract for long-term gas supplies from other sources, thus narrowing if not foreclosing the market opportunity for Alaskan gas.

This market risk is very real to the ANGTS sponsors; although some pipeline purchasers continue to project Alaskan gas in their future supply slates, this situation could change dramatically absent demonstrable progress on the ANGTS line.

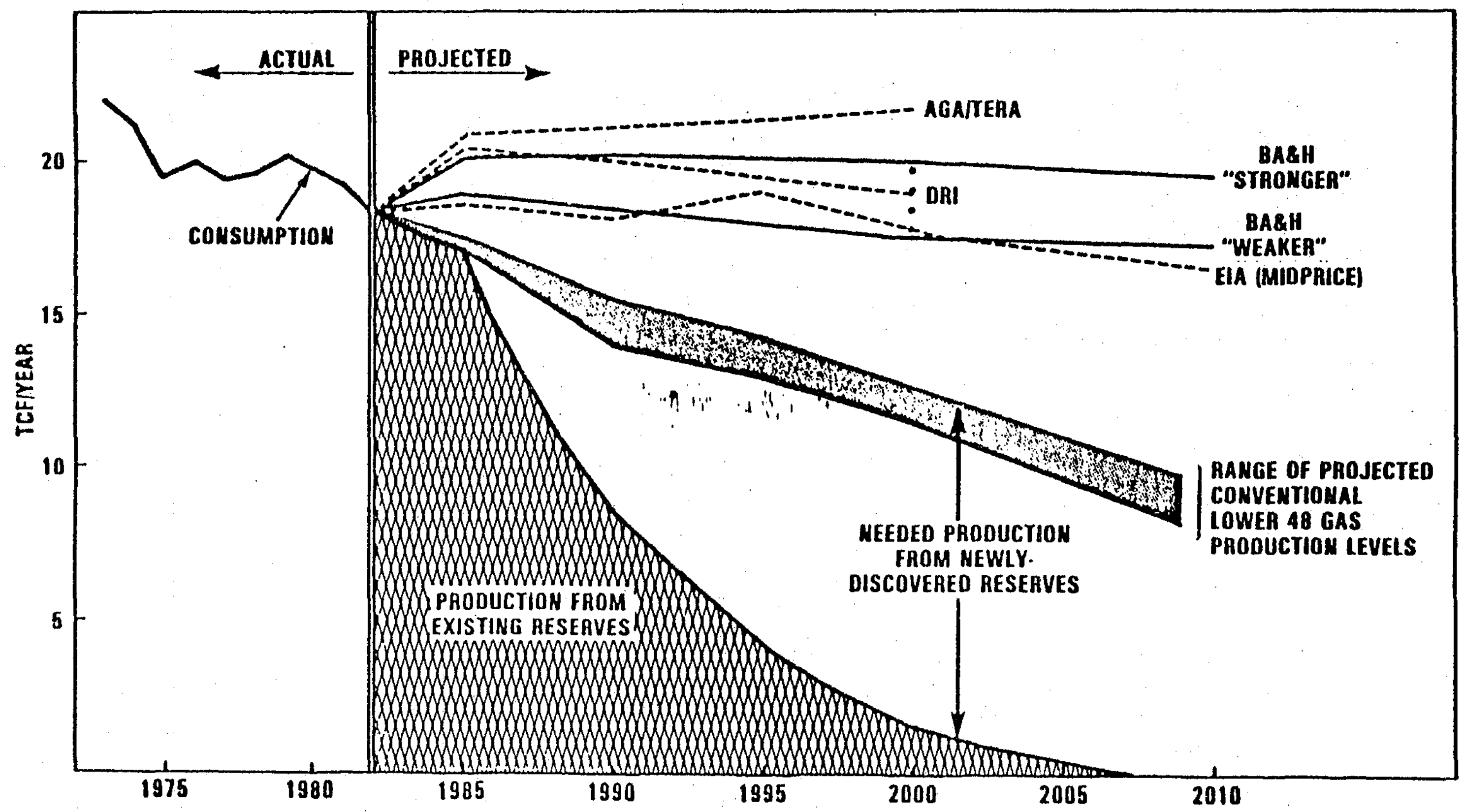
(2) **To penetrate Japanese markets, Alaskan gas products must be competitive with proposed LNG import projects.**

Two projects which utilize North Slope gas have Japan as their primary target market.

- LNG export as proposed by the Trans-Alaskan Gas System (TAGS)
- Methanol produced at a plant located in Fairbanks.

Exhibit III-6

FORECASTS OF LOWER 48 GAS SUPPLIES




SOURCE: ACTUAL: U.S. DEPARTMENT OF ENERGY, ENERGY INFORMATION ADMINISTRATION (DOE/EIA).
PROJECTED: EIA, ANNUAL REPORT TO CONGRESS, 1982: VOL. 3 (FEB. 1982); AMERICAN GAS ASSOCIATION (AGA), TERA SPRING BASE CASE (APR. 1982); DATA RESOURCES INC. (DRI), WINTER ENERGY REVIEW (FEB. 1982); BOOZ, ALLEN & HAMILTON INC.

For both products, the likely end-use market are electricity generation plants, although methanol does have the potential as a transportation fuel.

The projected market size addressable by Alaskan LNG and methanol is attractively large, although some uncertainty exists with respect to potential market demand. (Exhibit III-7) Moreover, the Japanese government's policy of reducing the country's dependence on imported -- primarily OPEC -- oil provides the opportunity for significant market penetration by natural gas and gas-derived products. While this is clearly a market of opportunity, the opportunity may be limited by ongoing negotiations for new LNG supplies, as depicted on Exhibit III-8. A number of factors may operate to inhibit entry of Alaskan LNG (and to a lesser extent Alaskan methanol):

- Absent robust economic growth, the demand projections depicted on Exhibits III-7 and III-8 may well be lower; even now, energy forecasts prepared by the Japanese Ministry of International Trade and Industry (MITI) are under scrutiny and may be revised downward. As further evidence of this potentially sluggish demand, buyers under the proposed Canadian and Australian import projects are now suggesting project start-up delays of two or more years beyond the original date of 1986 in order to balance demand (as reported by Petroleum Intelligence Weekly, Nov. 8, 1982).

- Political considerations will no doubt play a part in the import selection process. To enhance supply security, as well as to exercise control over prices, the Japanese have an announced preference for a broad mix of LNG suppliers. To overcome the current trade imbalance, and thus ease political tensions, Japanese import of Alaskan gas-derived products may well be advantageous; however, balanced against this political consideration is a perceived risk entailed with agreeing to a U.S. energy import project before it has been approved by regulatory authorities or obtained financing assurances.

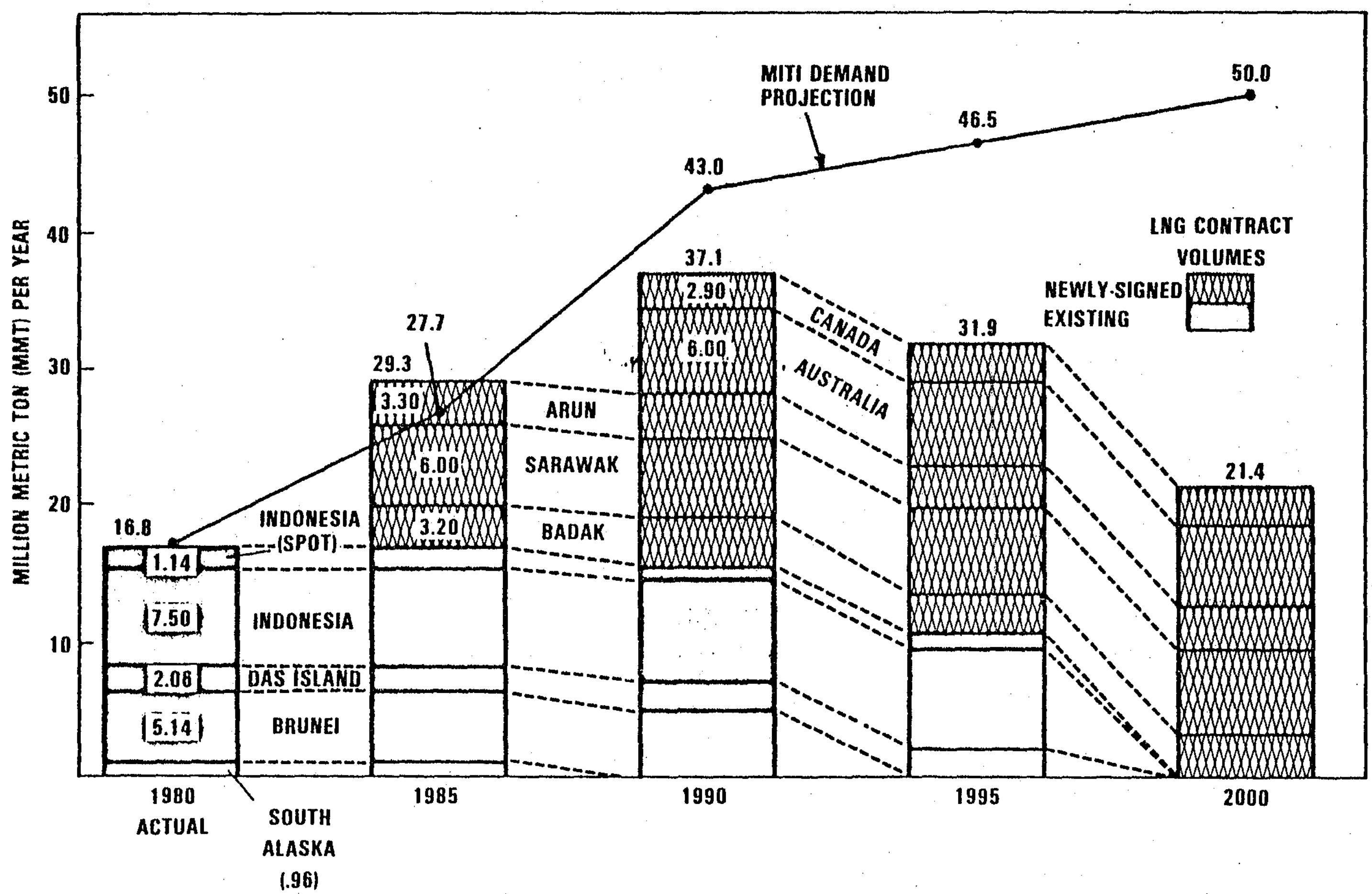
- Potential suppliers with low production costs, (e.g., Persian Gulf producers) could well absorb the somewhat higher marine transportation costs needed to access the Japanese market and thereby set a price level which is uneconomic for Alaskan deliveries. Gulf producers would have to do so, however, knowing their LNG sales would be used by customers to offset purchases of oil.

- Increasingly, gas-fired electricity generation will need to be competitive with alternative fuel sources. For example, the threat of low-cost coal imports or nuclear energy could gain market share at the expense of LNG. Electricity generated from nuclear capacity currently costs about 6 yen per kWh less than gas-fired electricity, and this differential may well increase in the future.

In short, the market prospects for Alaskan LNG and methanol in Japanese electric utility markets must be viewed with caution. The project sponsors of TAGS acknowledge the existence of a very narrow "window;" if Alaskan LNG is not landed in Japan during the period 1988-1990, this market could be foreclosed until after

Exhibit III-7

PROJECTED DEMAND FOR AND SUPPLIES OF LNG IN JAPAN




SOURCE: PETROLEUM INTELLIGENCE WEEKLY (NOV. 8, 1982); CANADIAN NATIONAL ENERGY BOARD, REASONS FOR DECISION IN THE . . . GAS OMNIBUS HEARING, 1982 (JAN. 1983); GOVERNOR'S ECONOMIC COMMITTEE, TRANS-ALASKAN GAS SYSTEM: ECONOMICS OF AN ALTERNATIVE FOR NORTH SLOPE GAS (JAN. 1983).

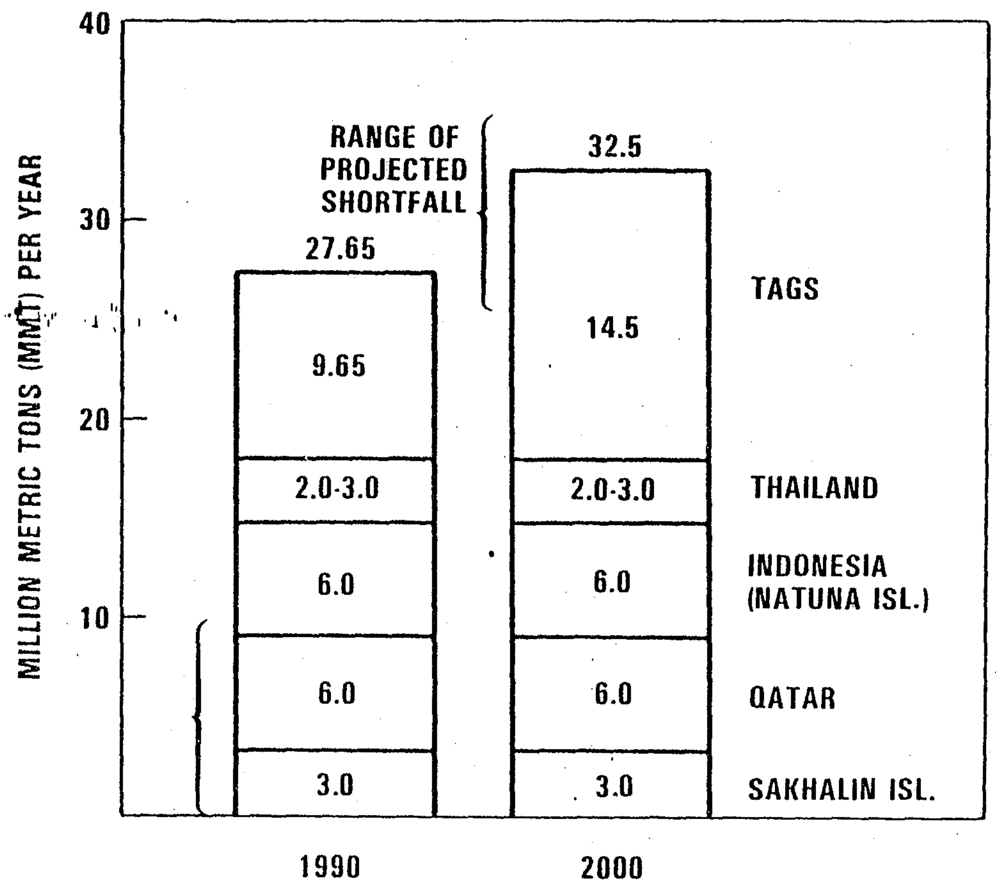
Exhibit III-8

# PROSPECTIVE LNG SUPPLY SOURCES TO MEET SHORTFALL IN JAPAN

## ESTIMATES OF LNG SUPPLY SHORTFALLS (MMT/YR)

| | 1990 | 1995 | 2000 |
|---|---|---|---|
| MITI | 5.9 | 14.6 | 28.6 |
| MITSUBISHI RESEARCH INSTITUTE | (0.1) | -- | 24.6 |
| MARUBENI | 4.9-8.9 | -- | 32.6-36.6 |
| SUMITOMO | 1.9-6.9 | -- | -- |
| MITSUI | 1.0 | -- | -- |
| RANGE | (0.1)-8.9 | | 24.6-36.6 |

## POTENTIAL LNG SUPPLY PROJECTS TO MEET SHORTFALL



2000. Clearly, however, having a firm contract of sale (i.e., a "deal") could eliminate many of these kinds of uncertainties.

In the Japanese market (and indeed in other Asian/Pacific Rim markets), LNG is traditionally priced against the landed cost of crude oil imports. Based upon the crude oil price paths developed for this study, this policy yields the LNG prices depicted on Exhibit III-9. These prices are considerably higher than the gas value in Lower 48 markets. Whether Alaska gas products could indeed obtain these price levels depends upon:

- The export price to be authorized by the Federal government for LNG
- The pricing strategy of other LNG exporters.

In the latter case, there exists considerable pricing disparity. For example, the contract signed with Dome Petroleum (Canada) agreed to a landed price of $6.86/MMBtu (in 1981 dollars), with escalation based on both the price increase of Saudi Light and the price of U.S. gas exports. In a contract between the government of South Korea and Indonesia for the importation of 2 MMT/year, a price of $5.78 per MMBtu exclusive of transportation from Indonesia has been set for 80% of the supply. In determining the likely wellhead netback price of gas delivered to Japanese markets as LNG, the prices as depicted on Exhibit III-9 have been employed.

The sponsors of the methanol plant have suggested that a slightly higher price could be charged for methanol in Japan and still be competitive; this premium would reflect the higher value of methanol in other end-use applications, as well as ease of transportability from the port of entry. However, the precise magnitude of this premium is difficult to quantify. Accordingly, the Btu-equivalent crude oil price as used for LNG has also been used for methanol in computing its netback wellhead value.*

**(3) As a fuel for in-state electricity generation, North Slope gas must be competitive with proposed hydropower projects**

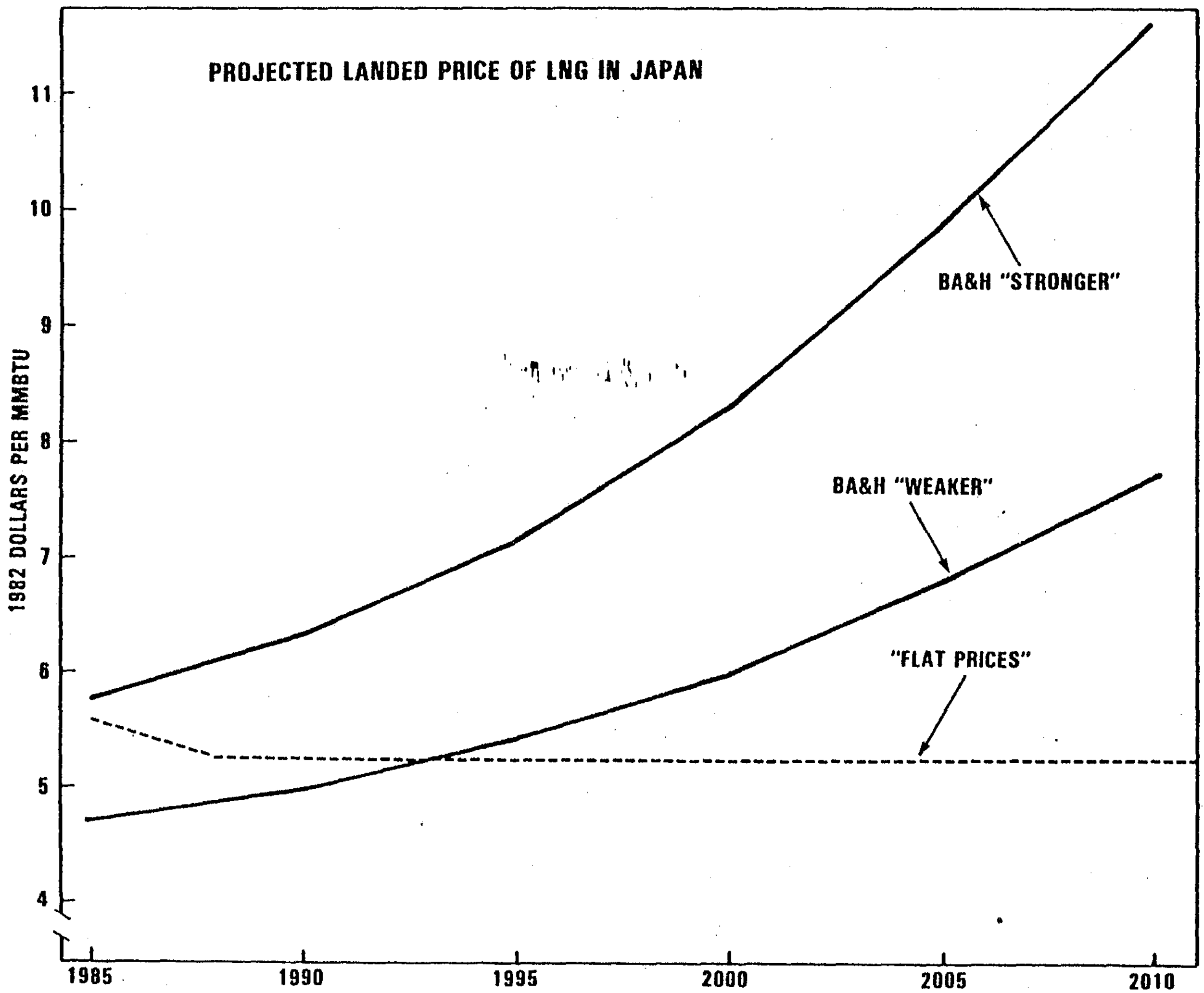
One suggested use for the State's royalty gas is as a fuel for electricity generation within the state. In an on-going study under the auspices of the Alaskan Power Authority, three potential generation sites have been proposed:

---

*The methanol plant sponsors have proposed deliveries to the U.S. West Coast as a secondary market, where methanol could be used in peaking plant electricity generation. In this market, methanol would primarily compete against natural gas (which held a 60.3% market share in 1981) and distillate fuel oil (39.2% share, at 5.8 T Btu/year). While the retail distillate price makes this an economically attractive market to penetrate, much of this price advantage is lost through higher transportation costs to U.S. ports, as discussed in greater detail in the technical report. Another -- hitherto unconsidered market -- would be in-state (Alaska) methanol use, both as an electric utility and home heating fuel in lieu of distillate. Although this market is too small to absorb the full volume of plant output, it does constitute an attractive market on the basis of price and lower delivery costs. However, in reflection of the project's marketing thrust, the economic analysis of this option has concentrated on the Japanese electric utility market for methanol.

Exhibit III-9

PROJECTED LANDED PRICE OF LNG AT "MARKET CLEARING" PRICE LEVELS IN JAPAN



- Generation on the North Slope

- Generation at Fairbanks, with the gas obtained either through a tap on the ANGTS or TAGS pipeline, or from a newly-constructed smaller-diameter pipeline terminating at Fairbanks

- Generation in Anchorage, with the gas transported through the TAGS line

To evaluate the attractiveness of this utilization option, Booz, Allen selected the Fairbanks generation site.

As distinct from the other end-use market assessments, the prospective demand for and price of electricity in Alaska was not driven by the energy/economic scenarios developed for this study. Prior extensive analysis has already been conducted on the prospects for electricity demand within the state, rendering additional analysis duplicative. A further consideration was the need for comparability with the assumptions being used in the Alaskan Power Authority study. Accordingly, in concert with the APA study, two ranges of electricity demand were selected; these are depicted on Exhibit III-10. Incremental generation capacity necessary to meet this demand under both the high and lower demand scenarios is set out on the right-hand side of the exhibit.

In order to meet the growing electricity demand within the state, several alternative generation schemes have been identified:

- Fossil-fired generation capacity, using oil, coal or natural gas for fuel

- Hydropower, (e.g., the Susitna project).

These generation options having differing capital and fuel costs, which affect the likely retail electricity price. The Susitna project, for example, has high capital cost (estimated at $5.1 billion, in 1981 dollars, for the full project size exclusive of financing costs); this cost is offset, however, by a zero cost for fuel.

The cost of electricity produced by hydropower -- as the lowest-cost source of electricity -- was used to set the price for North Slope gas in electricity generation; from earlier studies of the Susitna project, this cost has been estimated at 6.5¢/kWh. Alternative prices were also considered:

- The current price of electricity in the Anchorage area -- 7¢ per kWh

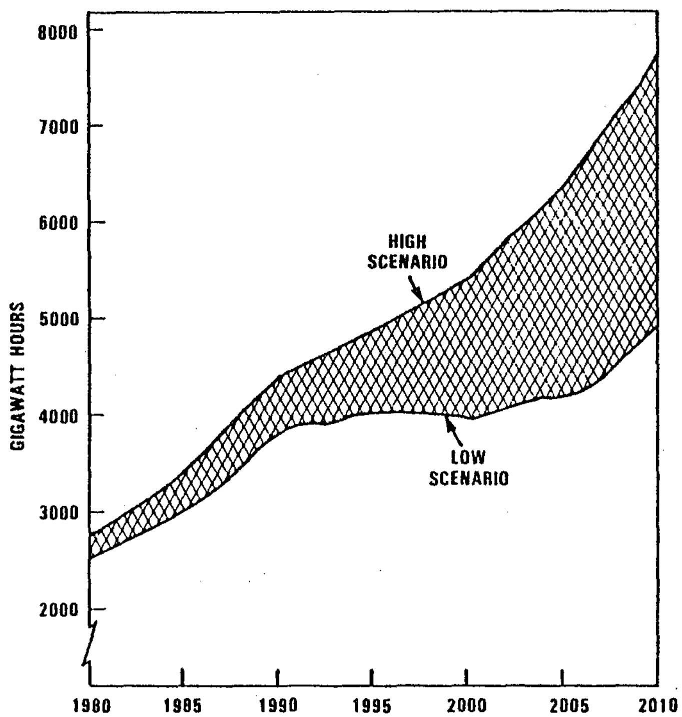
- A lower price of 4.5¢ per kWh -- the price of electricity cogenerated by the Fairbanks methanol plant.

To ascertain the maximum price which could be paid for North Slope gas and yield these delivered electricity prices, gas-fired combined-cycle plants were assumed constructed. This type of generating capacity determined both the gas fuel requirements and the plant construction cost. Subtracting generation and transmission costs from delivered electricity prices, and applying fuel usage rates,

Exhibit III-10

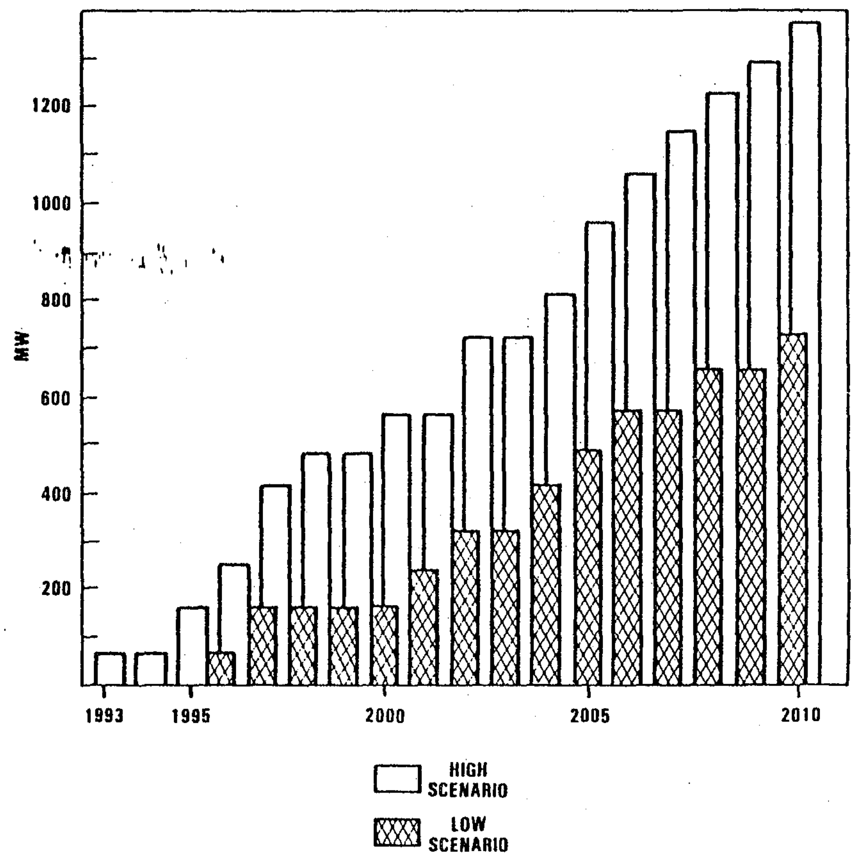
# FORECASTS OF ELECTRICITY CONSUMPTION AND GENERATING CAPACITY ADDITIONS FOR THE ALASKA RAILBELT

**FORECAST OF RAILBELT ELECTRICITY CONSUMPTION**




SOURCE: EBASCO, "USE OF NORTH SLOPE GAS FOR HEAT AND ELECTRICITY IN THE RAILBELT" (JAN. 1983)

**GENERATING CAPACITY ADDED TO MEET RAILBELT ELECTRICITY DEMAND**



yielded the city gate gas costs depicted on Exhibit III-11.* The city gate prices depicted on the exhibit reflect:

- The three retail electricity price levels (i.e., 4.5¢, 6.5¢ and 7.0¢/kWh)
- The range of electricity demand levels (i.e., "low" and "high" demand).

As shown in the exhibit, the maximum affordable price of gas rises over the forecast period, which occurs from application of a "cost-of-service" approach to estimate generation and transmission costs; under such a pricing methodology, fixed charges (capital) and O&M expenses tend to decline in real dollar terms over the life of the plant.

(4) **The wellhead value of North Slope oil production is determined by the price of crude imports at U.S. Gulf Coast ports.**

The value of the gas used for an enhanced oil recovery (EOR) project will be based upon:

- The value of the incremental oil flow resulting from such recovery methods
- The timing and volume of such incremental oil flows.

The wellhead price of North-Slope crude has traditionally been set on a netback basis from a Gulf Coast port of entry. While approximately half of North Slope oil production is utilized by West Coast refineries, the Gulf Coast -- rather than the West Coast -- serves as the price setter since it is the marginal market for these supplies. Transporting oil from the North Slope to the U.S. Gulf Coast averages $10-11/bbl currently. Two factors may cause these transportation costs to decline slightly in the future:

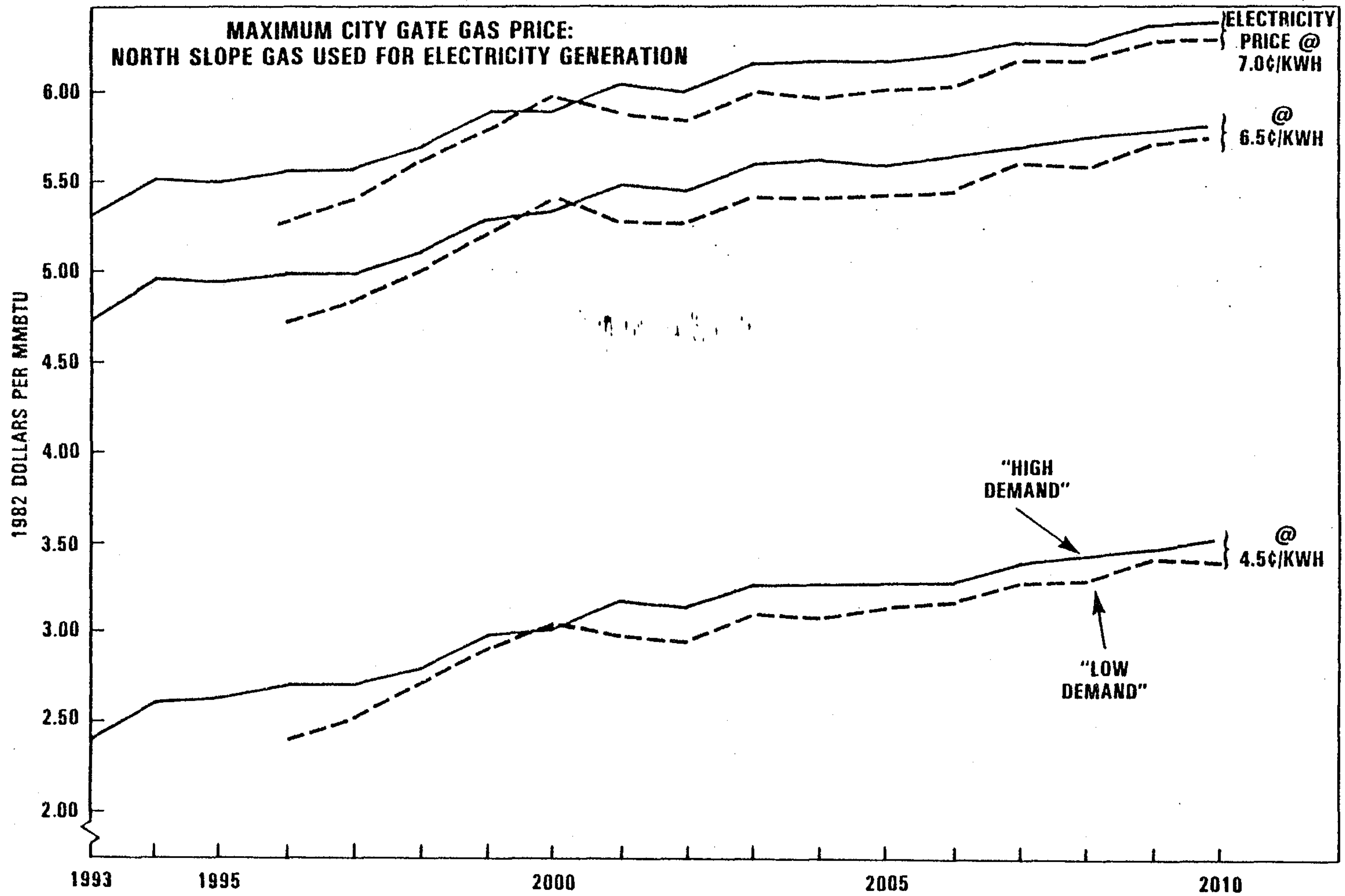
- Reduction in the Trans-Alaskan oil pipeline (TAPS) tariff, which presently averages $6/bbl; as the rate base is depreciated, the lower capital charge per unit of throughput results in a lower transportation cost expressed in real and nominal dollars
- Potential savings by transporting oil through the newly-constructed Panama Isthmus pipeline, rather than tanker shipment through the Panama Canal.

---

*In addition to electricity generation, North Slope gas could also be sold in the Fairbanks area to residential, commercial and industrial customers through a newly-constructed gas distribution system. Using an approach similar to that for electricity generation, a maximum affordable citygate gas cost for such gas sales could be calculated; however, data on the cost for such a gas distribution system and the likely volume of annual direct gas sales has not been developed to date.

Exhibit III-11

PROJECTED MAXIMUM AFFORDABLE CITY GATE PRICE FOR NORTH SLOPE GAS USED FOR ELECTRICITY GENERATION



To be conservative, however, a transportation cost allowance of $11 per barrel (in constant 1982 dollars) was applied throughout the forecast period.* An additional $1/bbl was added to the transportation cost, to reflect the price effect from the quality differences between North Slope crude and Saudi Light ("OPEC marker" crude). This cost differential, when applied to the three crude oil price trajectories, results in the netback wellhead prices depicted on Exhibit III-12. For comparison, the Alaska Department of Revenue's projection of North Slope crude prices is also plotted on the exhibit. The State forecast -- predicated upon flat world oil prices until 1985 and increasing by 7.5%/year on average thereafter (in nominal dollar terms) -- shows a slight decline in near-term wellhead prices, due to world oil market conditions and to tax policies (i.e., Windfall Profits Tax) which encourage profit taking at the refinery rather than the wellhead; as world oil prices rise after 1986, and real transportation costs decrease, the wellhead oil price gradually climbs to $27.50/bbl by 1998 (in 1982 dollars).

There should be little difficulty in marketing any incremental oil production arising from EOR in North Slope fields. The values expressed on Exhibit III-12 could indeed be increased if transportation costs were lowered through:

- Oil sales to non-U.S. markets (e.g., Pacific Rim markets such as Japan)
- Marketing all North Slope production to the West Coast refineries.

However, higher wellhead oil values are not very likely; West Coast oil markets are incapable of absorbing the full volume of North Slope oil production. Despite past -- and continuing -- discussions to export Alaskan oil to Japan, there appears to be no strong movement to repeal the current legislative ban so long as the U.S. continues to rely on imports to meet domestic demand.

3. THE PRICE SCENARIOS IMPLY DIFFERENT MARKET OPPORTUNITIES FOR THE PROJECTS STUDIED.

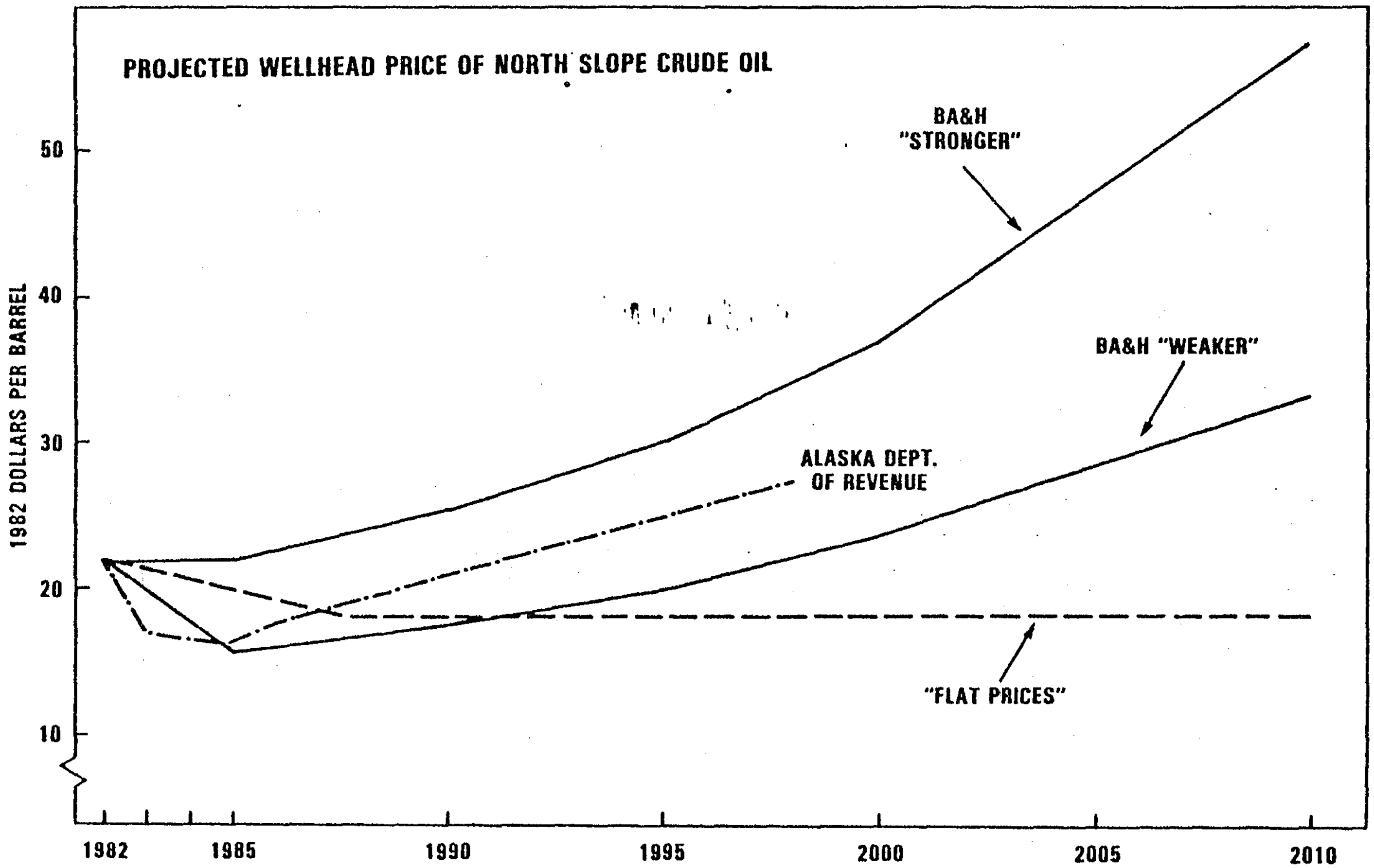
The retail price levels, market demand and competitive pressures from other suppliers differ under the five world oil prices scenarios. These market conditions imply different -- rather than similar -- marketing opportunities, particularly for projects planning to export North Slope gas and gas-derived products.

---

*In their June 1982 Forecast, the State Department of Revenue, Petroleum Revenue Division, assumed that the FY 1982 transportation cost of $10.62/bbl would decline to $9.12/bbl by 1998 in nominal dollars, or to $2.80 in constant 1982 dollars. (Petroleum Production Revenue Forecast: Quarterly Report, June 1982).

Exhibit III-12

PROJECTED WELLHEAD PRICES FOR NORTH SLOPE CRUDE OIL



- **The lower oil price scenarios entail difficult marketing prospects in both the U.S. and Japan.**

The three lower price scenarios -- "weaker economy," "low prices," and "flat prices" -- envision relatively slack economic growth and, as a consequence, soft energy demand. In light of existing LNG contracts and a reduced incentive to displace oil use, entry of additional Alaskan LNG into Japan and other Pacific Rim markets might be delayed. The economic feasibility of the project is doubly strained -- both by low market prices and the prospects of heightened competition for market share from energy-exporting nations seeking to maximize hydrocarbon revenues.

Market prospects, although difficult, may be somewhat better in the Lower 48 states than in Japan in the low oil price cases. While gas demand and gas prices are low, there would be less incentive to develop marginal gas reserves, leading to a enough of a prolonged drilling downturn than in Japan tighten domestic supplies -- thereby providing a market opportunity for Alaskan gas in the 1980s.

- **In the "stronger economy" scenario, market prospects are brighter in Japan, while worsening in the Lower 48.**

The higher oil prices, coupled with stronger economic growth, improve the market prospects for Alaskan LNG (and methanol) in Japan:

  - More robust energy demand and greater incentive to displace oil increases the market size

  - Higher retail prices enhances project economic feasibility, and offers some pricing flexibility to meet competitive pressures from alternative suppliers.

The reverse situation occurs in Lower 48 markets, as higher prices and greater demand stimulate development of Lower 48 gas fields, including tight sands and deep gas, as well as such supplemental supplies as synthetic gas from coal.

- **While an oil supply disruption represents the best market opportunity, relying upon such an event for project feasibility is highly risky.**

A disruption in world oil supplies -- with a sharp run-up in energy prices -- would ease market entry and offer maximum market prices for North Slope gas exports:

  - Increase Japanese LNG demand, while possibly reducing price and market share competition from other supply sources which are receiving "windfall" revenues

  - Unsatisfied U.S. energy demand turning to gas (and perhaps encouraged in that direction through government regulations), while Lower 48 gas producers could be unable to respond quickly with additional gas supplies.

However, the timing and probability of such an event is highly uncertain; relying upon this scenario to achieve economic feasibility would be highly risky for a project sponsor.

In-state gas use for electricity generation is also affected by the different energy/economic scenarios, since state economic growth -- and thereby electricity demand -- is influenced by petroleum revenues. Thus, the lower oil price paths would likely cause the "low electricity demand" projection to prevail, while "high electricity demand" projection would require the "stronger economy" price scenarios.

* * * *

To summarize, end-use market demand and likely retail price has been assessed for the primary markets targeted for sales of Alaskan North Slope gas:

- Natural gas delivered through the ANGTS line to the Lower 48
- Deliveries of LNG and methanol to Japanese markets
- Plant gate price of gas delivered to Fairbanks for purposes of electricity generation.

On balance, Japan is a higher value market than the Lower 48 states, with retail prices ranging 20-25 percent higher and the advantage on a wholesale market basis being even wider. However, Japan's prior LNG contract commitments make entry difficult for Alaskan LNG. Even if constructed by 1988-1990, gas export through TAGS might not secure market share until the mid-1990's.

# IV. ESTIMATION OF WELLHEAD GAS VALUE

A key element in assessing the economic feasibility of the alternative options for North Slope gas is the maximum value at the wellhead obtainable under each project. A high wellhead value offers the following advantages:

- Provides greater **incentive** on the part of producers **to develop Arctic gas resources,** since these resources can be marketed at a favorable price

- Demonstrates the economic viability of a project, thus **enhancing the probability of project financing** by private funding sources

- Offers some pricing leeway to permit project sponsors to **penetrate the targeted markets in a timely and successful fashion.**

A large negative wellhead value, or a negative value which persists for several years into the project lifetime, is clearly undesirable. Not only could producers lose revenues, but the State too would lose the royalty value of the gas being produced while securing only minimum severance tax payments.

A netback gas value was estimated for the four projects under study, using the approach depicted on Exhibit IV-1.* The cost of converting the gas into end-use products and associated transportation costs are calculated from project construction and operating cost parameters. These costs, expressed on a per-unit basis, are then subtracted from the likely retail price in the end-use market. After accounting for the cost of gas consumed in the conversion/transportation process, a netback wellhead value is derived.

In deriving the processing and transportation costs, the capital structure and cost estimates as supplied by the various project sponsors were used. These "baseline" cost assumptions are set out on Exhibit IV-2. Sensitivity tests were conducted on both the ANGST and TAGS cost and operating assumptions -- due both to the volume of gas envisioned under each project, and for their impact on ancillary projects based in Fairbanks (the electricity generation and methanol plants). This sensitivity analysis is described in a later section of this chapter, and the results detailed in the technical appendices.

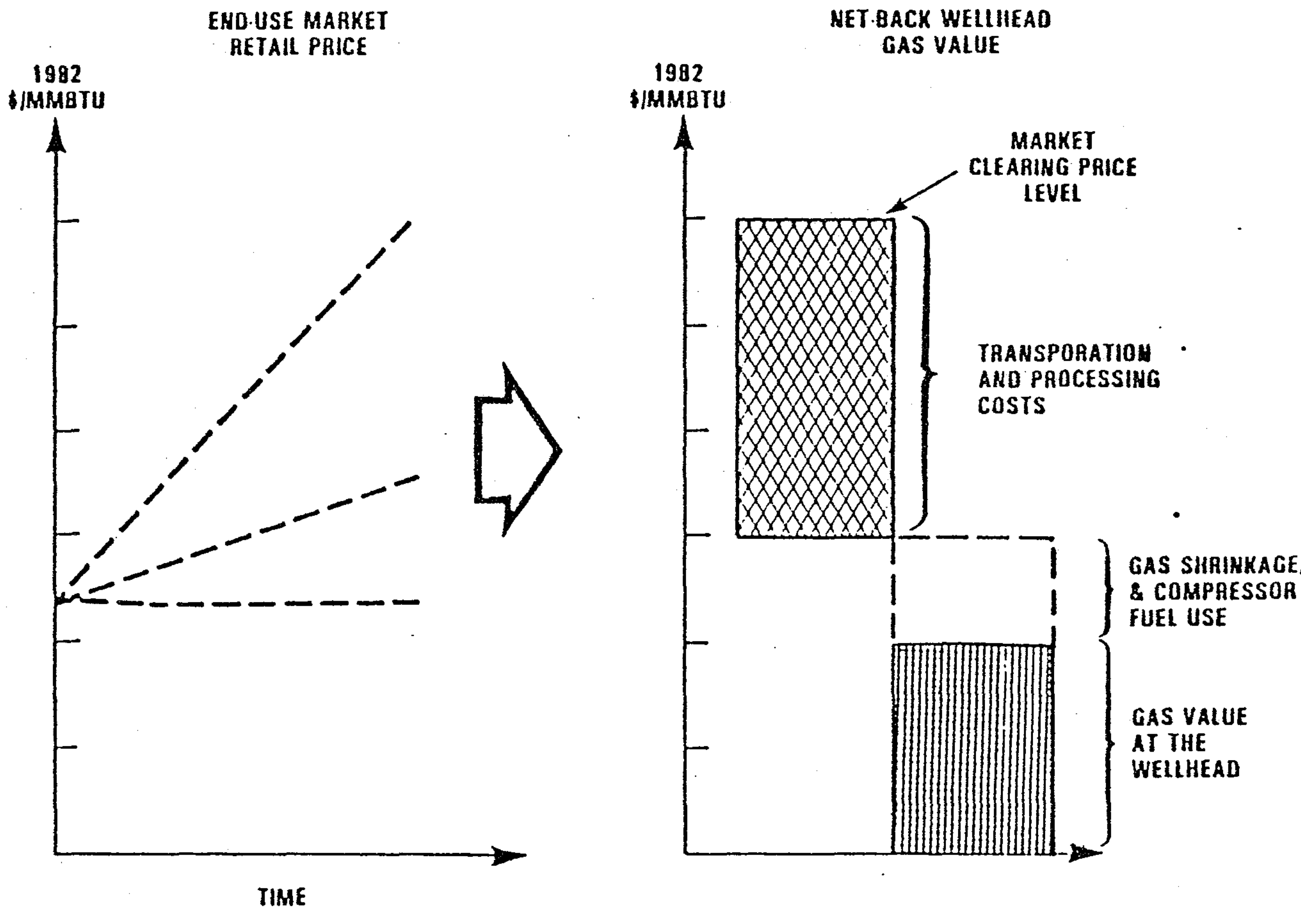
To calculate annual transportation and processing costs for each project, a **cost-of-service** methodology was employed. This method, common in utility-type projects, yields a declining cost in real dollar terms as the rate base (invested capital) diminishes through capital recovery (depreciation expense). The Governor's Economic Committee, in assessing the economic feasibility of the TAGS system, developed a **levelized tariff** cost, whereby unit costs remain constant in real dollar terms, and increase in nominal dollar terms. Exhibit IV-3 depicts the unit costs arising from the two pricing methodologies. Under a cost-of-service or utility pricing approach, unit costs in the

---

*Insufficient project cost and productivity data were available to enable inclusion of the fifth option -- EOR -- in this part of the analysis.

Exhibit IV-1

NETBACK APPROACH FOR DETERMINING WELLHEAD GAS VALUE



## Exhibit IV-2

## PROJECT COST ASSUMPTIONS USED AS THE "BASELINE" COST CASE

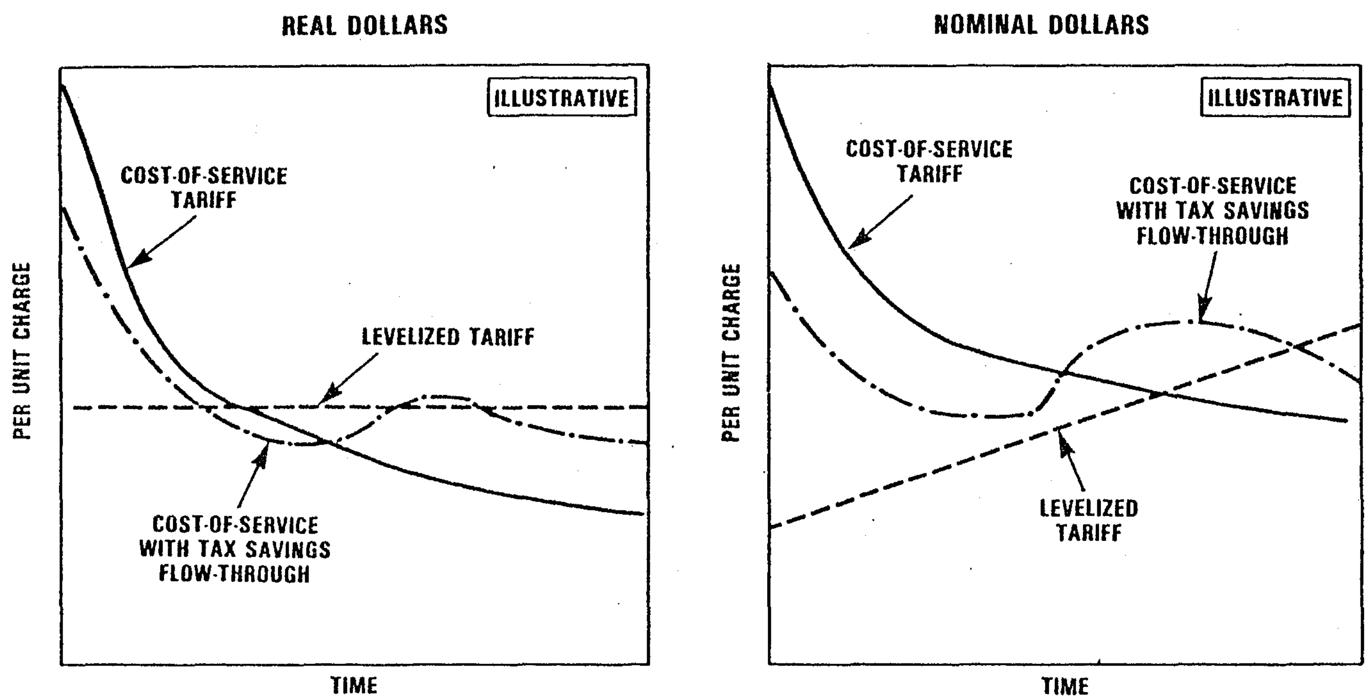
| PROJECT | CAPITAL COST[1] (MILLIONS OF 1982 DOLLARS) | CAPITAL STRUCTURE | | NOMINAL COST OF CAPITAL | |
|---|---|---|---|---|---|
| | | DEBT | EQUITY | DEBT | EQUITY |
| ANGTS | CONDITIONING PLANT: $ 3.954.6<br>ALASKAN PIPELINE: 10,186.2<br>CANADIAN PIPELINE: 6,231.5[2]<br>EASTERN LEG: 2,037.2[2]<br>WESTERN LEG: 1.078.5[2]<br>TOTAL $23,488.0 | .75 | .25 | 10.0%<br>10.0<br>10.0<br>10.0<br>10.0 | 14.0%[3]<br>17.5[3]<br>17.7[3]<br>15.0[3]<br>13.5 |
| TAGS | PHASE I: $ 7,173<br>PHASE II: 10,253<br>PHASE III: 14,294 | .75 | .25 | 14.0% | 18.0% |
| METHANOL PLANT | LOW: $ 578.3<br>HIGH: 728.3 | .70 | .30 | 10.0% | 15.5% |
| ELECTRICITY GENERATION | LOW: $ 589.6<br>HIGH 1,120.9 | 1.00 | -- | 10.5% | -- |
| EOR | (DOLLAR VALUE OF EOR NOT DEVELOPED IN THIS ANALYSIS) | | | | |

1. CUMULATIVE: EXCLUDES ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION.
2. INCLUDES PRE-BUILT COSTS.
3. APPLICABLE DURING CONSTRUCTION TERM ONLY; WHEN OPERATIONAL, ALLOWED ROE IS: 16% (CONDITIONING PLANT), 14% ALASKA PIPELINE), 18% (CANADIAN PIPELINE), AND 13% (EASTERN LEG).

ADDITIONAL ASSUMPTIONS:
- INFLATION RATE OF 7%/YEAR, 1983-2010 (U.S.), 8%/YEAR (CANADA).
- TIMING OF CONSTRUCTION EXPENDITURES BASED ON PROJECT SPONSOR ESTIMATES; INITIAL YEAR OF OPERATION IS 1990 FOR ALL PROJECTS EXCEPT ELECTRICITY GENERATION, WHERE INITIAL OPERATION IS 1993 (HIGH SCENARIO) OR 1996 (LOW SCENARIO).
- FOR INCREMENTAL CAPITAL BORROWING, AFUDC ASSESSED ON AVERAGE AMOUNT BORROWED DURING THE YEAR (I.E., ONE-HALF OF FULL YEAR'S INCREMENTAL EXPENDITURE).

Exhibit IV-3

TRANSPORTATION/PROCESSING COSTS UNDER ALTERNATIVE PRICING METHODS



initial years of operation can be lowered by applying tax savings to directly reduce revenue requirements, rather than passing such additional cash flows to project financiers; when tax benefits are exhausted, annual tariff charges begin to exceed cost-of-service levels in real and nominal dollars. This pricing variant was used as a sensitivity case for the ANGTS and TAGS lines.*

The remaining sections of this chapter describe:

- The transportation and processing costs associated with each alternative
- The wellhead value obtainable under each project, based on these costs and the end-use retail prices as described in the preceeding chapter

Due to the lack of data, the enhanced oil recovery (EOR) option could not be evaluated.

## 1. THE RELATIVELY HIGH CAPITAL COSTS FOR ANGTS AND THE METHANOL PLANT RESULT IN HIGHER ANNUAL OPERATING COSTS FOR THESE TWO OPTIONS

As between the two large-scale options, ANGTS has the higher operating costs -- and thereby higher delivered gas cost -- due to its greater construction cost. This result could well be reversed, however, if

- More detailed engineering studies conducted on the TAGS project were to lead to upward cost revisions
- Gas throughput does not rise above levels envisioned in Phase I of the project.

Both projects have lower transportation costs for gas delivered to Fairbanks than a small-diameter pipeline built to transport gas solely from the North Slope to Fairbanks.

In the case of the two smaller-scale projects based in Fairbanks, the methanol plant has higher processing and transportation costs than the electricity generation option. For the former, rail transport costs -- primarily tank car lease expenses -- add significantly to project operating costs.

These findings are discussed in greater detail below.

---

*Alternatively, tax savings from accelerated depreciation and the investment tax credit can be retained by project financiers, and indirectly reduce revenue requirements and unit tariff charges by lowering:

- Interest costs -- through early debt retirement
- Return on equity payments -- through early repayment of equity capital invested
- Federal income tax payments in later years -- by reducing pre-tax operating income by the amount of after-tax (return on equity) income saved.

The Governor's Economic Committee, in computing the TAGS tariff, assumed retention of tax savings by project owners/lenders. In the present analysis, however, tax savings were flowed through to the gas shippers directly.

(1) ANGTS has higher delivered gas costs than TAGS, reflecting its higher construction cost

Exhibit IV-4 depicts the gas transportation costs of the ANGTS and TAGS systems, annually and on average over the first 20 years of operation. In the case of the ANGTS system, delivered costs are shown separately for Eastern and Western Legs, with the latter's costs averaging approximately 10¢/MMBtu higher. Because of the phased construction proposed for TAGS, initial costs decline sharply as throughput increases from Phase I levels. As shown on the exhibit, the ANGTS operating costs are slightly higher than TAGS on a yearly basis.

This result is not surprising, given the underlying capital costs associated with TAGS versus the ANGTS system. The costs differences are partly attributable to the differences in system configuration.

- The TAGS system assumes that, for its initial compressor station on the North Slope, it will utilize an existing compressor station (operated by the Prudhoe Bay oil producers). If instead a new compressor were necessary, the capital costs for the TAGS system would increase by approximately $1 billion.*

- Locating the TAGS conditioning plant in Anchorage, rather than on the North Slope, provides savings both in transporting the conditioning plant modules, and in fabricating the plant. As a result of this and other differences, the TAGS conditioning plant is estimated to cost $1.4 billion in 1982 dollars as compared with nearly $4 billion for the ANGTS, for plants of comparable operating capacity.

In addition, the premises under which each system's costs were developed should be considered. In the case of ANGTS, engineering work -- and hence project costing -- is more advanced than for the TAGS system; when more detailed routing and siting work is undertaken, the TAGS costs may change. In addition, there exists a disincentive on the part of the ANGTS sponsors to underestimate project costs; under the "incentive rate of return," failure to construct the ANGTS project on time and within budget results in a reduction in the rate of return permitted the equity sponsors. The conservatism which this rate setting technique encourages can be seen in pipeline construction costs estimates for the two systems.

- ANGTS pipeline costs -- including 7 compressor stations totaling 10-26,000 Hp compressor units and 730 miles of pipe -- average $14.3 million per mile (1982 dollars, excluding allowance for funds used during construction).

- TAGS pipeline cost -- including 14 compressor stations (size not stated) and 820 miles of line -- average $10.1 million per mile.

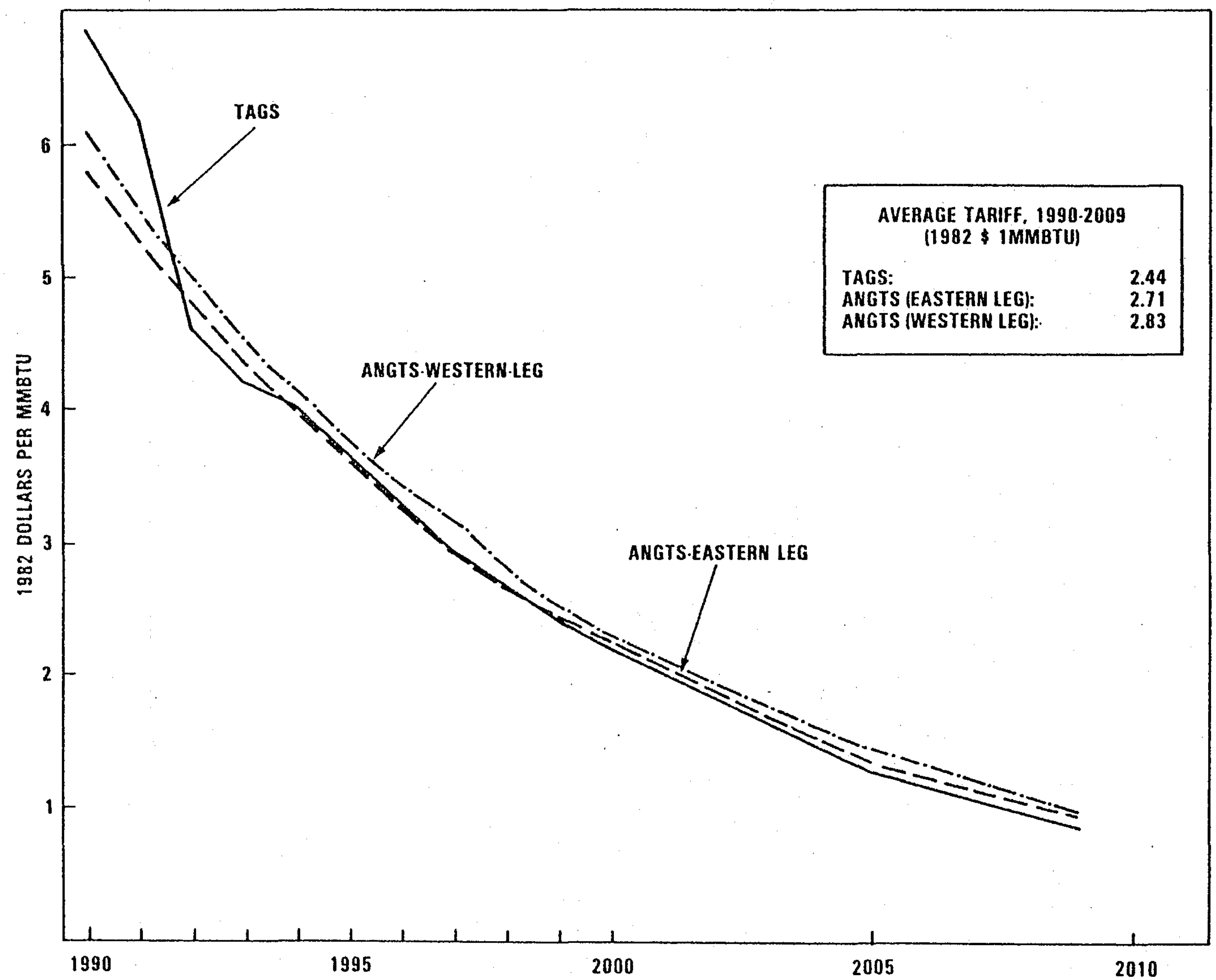
Furthermore, in the case of TAGS, a 20% contingency was assumed by the sponsors in the "baseline" costs used in Exhibit II-4, while approximately a 46% contingency was used in the ANGTS "sponsors' current filing" (baseline case) shown on the exhibit (the product of about a 12% normal and 30% extraordinary risk contingencies).

---

*Except where otherwise noted, all cost figures are in 1982 dollars.

Exhibit IV-4

ANNUAL OPERATING COSTS FOR THE TAGS AND ANGTS SYSTEMS




NOTE: EXCLUDES COST OF GAS USED AS COMPRESSOR FUEL

Sensitivity tests were conducted on these "baseline" cost estimates for the TAGS and ANGTS system. Some of these sensitivity tests we conducted -- as described in greater detail in the technical appendix report -- entailed possible variations in the cost of capital for the TAGS system, and in construction costs of the ANGTS system. In contrast to "baseline" project costs, for example, these cost sensitivity tests resulted in weighted average cost variations of:

| | Lowest Cost | Baseline Cost | Highest Cost |
|---|---|---|---|
| ANGTS (through Eastern Leg) | \$2.50 | \$2.71 | \$3.15 |
| TAGS | 2.22 | 2.44 | 2.89 |

on average over the initial 20-year operating period (excluding compressor fuel).

For both the TAGS and ANGTS systems, by far the largest cost component is the Alaskan pipeline segment, as demonstrated in Exhibit IV-5. The TAGS project also requires LNG transport from the Kenai Peninsula to Japan. The costs shown on Exhibit IV-5 -- 32¢ per MMBtu under the "weaker" economy scenario -- were derived from tanker operating and capital costs as prepared for the U.S. Maritime Administration by ICF Inc.; these costs were suggested by the TAGS proponents (the Governor's Economic Committee) as being representative and acceptable measures of LNG transport costs. However, the Committee undertook an independent analysis of tanker costs under three alternative scenarios.

- Construction of a new dedicated LNG fleet
- Chartering existing LNG tankers
- Chartering the presently-inactive El Paso LNG tanker fleet

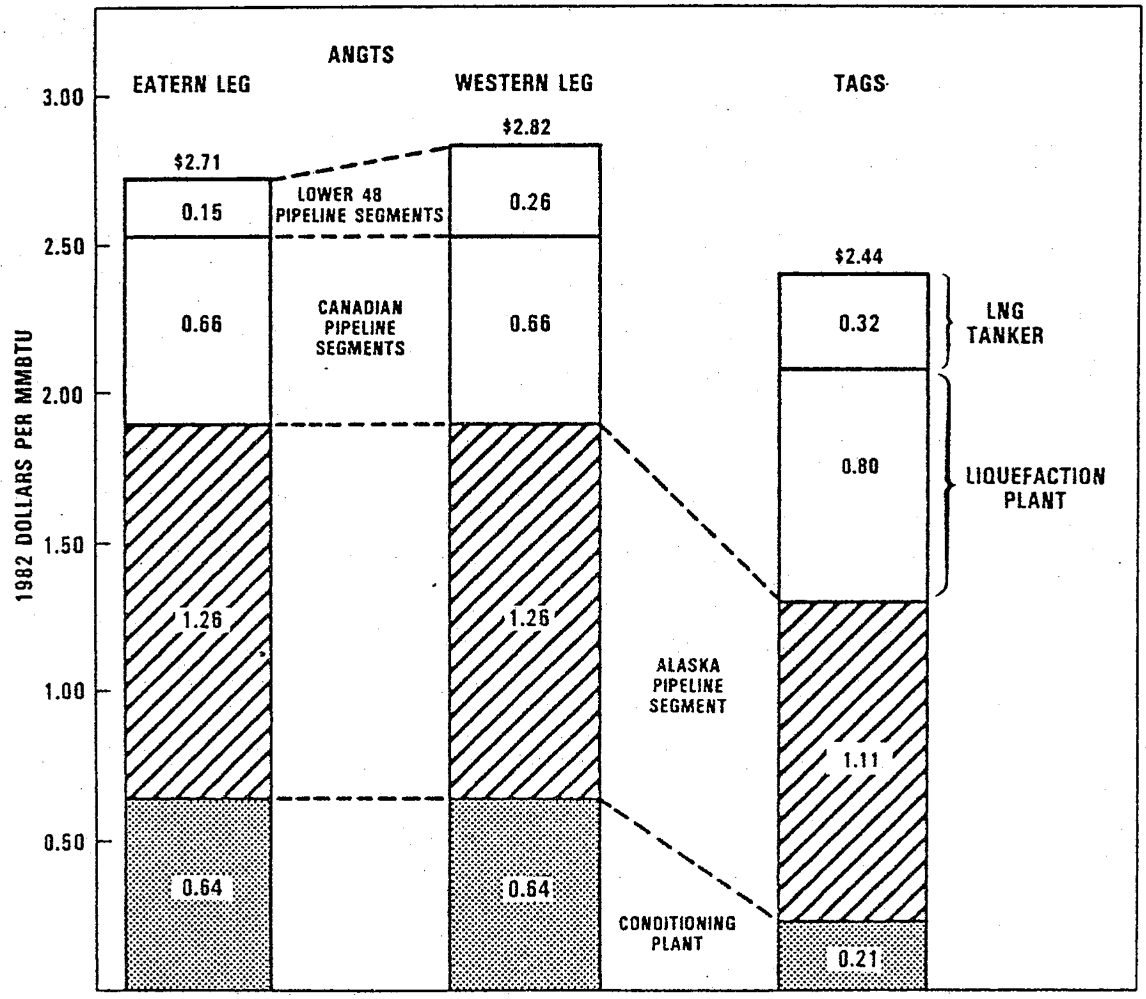
The transportation costs associated with these different fleet configurations are contrasted with the cost assumptions as derived from the Maritime Administration study on Exhibit IV-6. These transport costs have important implications for the potential competitive position of Alaskan LNG in the Japanese market vis-a-vis alternative LNG suppliers.

- Several incremental LNG suppliers to the Japanese market -- for example, Canada and Indonesia -- are approximately the same distance from the Japanese market as is the Kenai Penninsula. To the extent, therefore, that these supply sources have lower pipeline costs to the LNG export port, these suppliers could underprice Alaskan LNG, regardless of which tanker cost estimate best reflects shipping costs to Japanese markets.

- Incremental supplies from Middle Eastern markets (Saudi Arabia, Kuwait, and Qatar) are approximately twice as far from Japan as is Alaska, suggesting that transport costs would be approximately double that of costs from Alaska. Since gas fields in these countries are relatively near a port of exit, pipeline costs to a liquefaction plant could be much lower than gas transport cost in Alaska. Indeed, in all cases except the highest LNG tanker cost, these suppliers could absorb twice the LNG transportation costs depicted on Exhibit IV-6 and still land LNG in Japan below the Alaskan price.

Exhibit IV-5

TAGS AND ANGTS COST COMPONENTS AVERAGED OVER PROJECT OPERATING LIFE




NOTE: EXCLUDES COST OF GAS USED AS COMPRESSOR FUEL.

TAGS' COSTS ARE WEIGHTED AVERAGE, TO REFLECT INCREASING VOLUME THROUGHPUT; TANKER COSTS ARE FOR "WEAKER ECONOMY" COST (AFFECTING BUNKER FUEL COST)

Exhibit IV-6

ESTIMATES OF LNG SHIPPING COSTS FROM THE KENAI PENNINSULA TO JAPAN

A. BOOZ, ALLEN:*

| Cost Case | Average Delivered Cost (1982 $/MMBtu) |
|---|---|
| "Weaker Economy" | 32¢ |
| "Stronger Economy" | 37¢ |
| "Flat Prices" | 30¢ |

B. GOVERNOR'S ECONOMIC COMMITTEE:**

| Cost Case | Average Delivered Cost (1982 $/MMBtu) |
|---|---|
| New LNG Tankers | 111.4¢ |
| Chartered Tankers | 66.1¢ |
| El Paso Tankers (Chartered) | 58.5¢ |

* Based on cost LNG tanker cost data contained in ICF, Inc. report (Alaska Natural Gas Development: An Economic Assessment of Marine Systems. September 1982)

** Cost estimated prepared by En-Mar Resources, Inc. for the Governor's Economic Committee report (Trans Alaskan Gas System: Economics of an Alternative for North Slope Gas. January 1983.)

(2) **To deliver gas to the Fairbanks area, a tap on the TAGS or ANGTS system is more economical than a dedicated small-diameter pipeline**

To supply North Slope gas to either -- or both -- of the smaller-scale projects located in Fairbanks, transportation could be effected by either of three options:

- A tap on the TAGS line, which passes approximately 20 miles northwest of Fairbanks

- A tap on the ANGTS line, which passes approximately 20 miles northeast of Fairbanks

- Constructing a 480-mile small-diameter pipeline from the North Slope to the Fairbanks city gate.

To assess the latter option, a "cost-of-service" tariff was calculated as shown on Exhibit IV-7; construction costs -- estimated at $3 million per mile (1982 dollars) by several independent engineering consulting firms -- are appropriate for a 16-20 inch diameter line. As shown on the exhibit, two different forms of ownership -- with different costs of capital -- were evaluated.

- State (public) ownership -- with a cost of capital at 10.5% (nominal), which reflects the state's cost of capital (whether on funds borrowed through a bond issue or lent directly from state revenues)

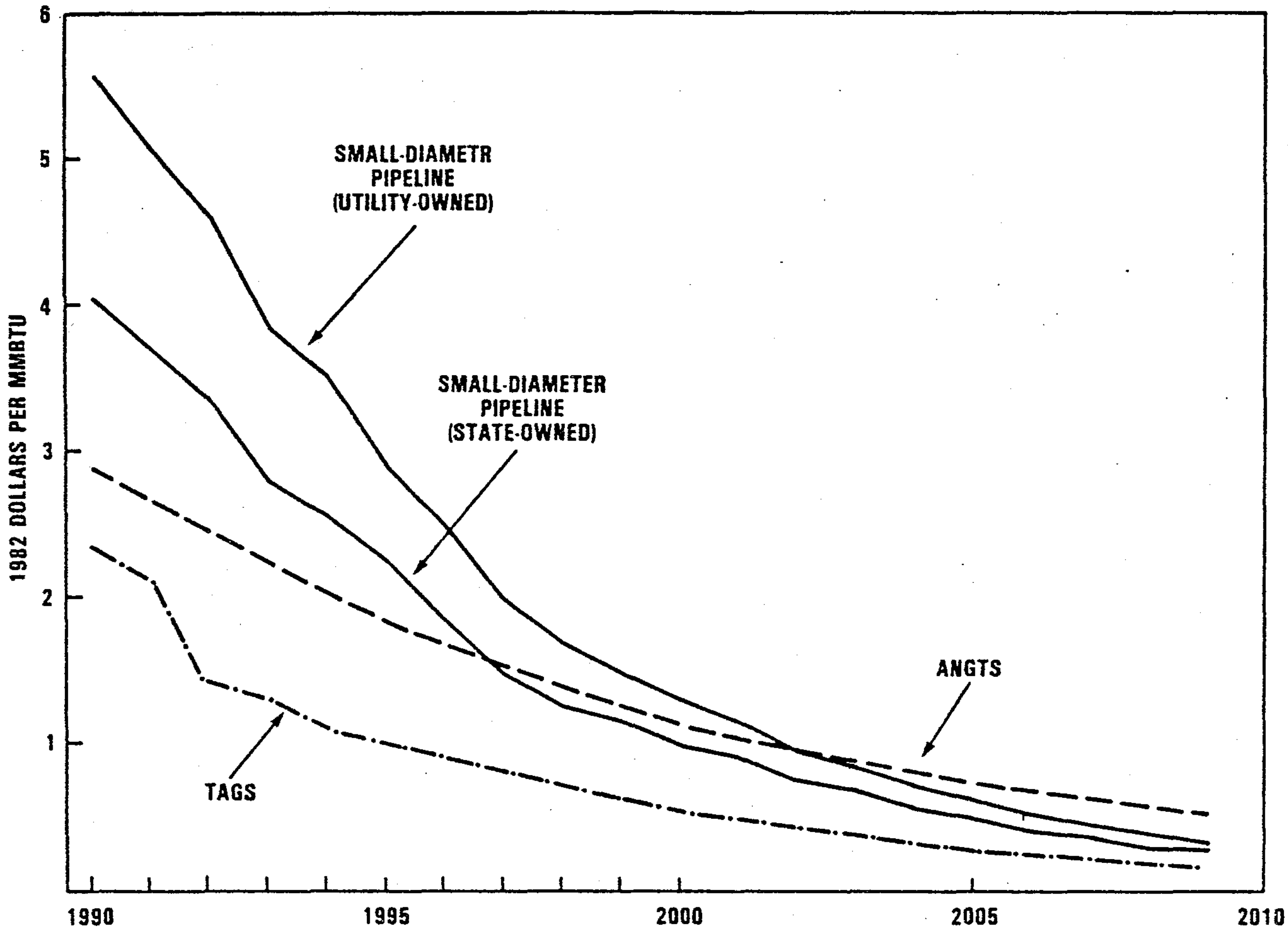
- Public utility (investor-owned) -- with a capital structure and cost of capital comparable to the TAGS or ANGTS systems.

Exhibit IV-7 compares the transportation costs of a small-diameter pipeline with the likely tariff charge of gas delivered to Fairbanks by the ANGTS or TAGS system. For this comparison, the tariff charged by ANGTS and TAGS for deliveries to Fairbanks were estimated at 60% of annual operating costs for the full Alaskan pipeline length -- to reflect the scale of construction costs north and south of Fairbanks. The steady decline in the small-diameter pipeline cost reflects both the rise in throughput after 1993 as increasing gas volume are used for electricity generation and the decreasing ratebase. Delivery costs through ANGTS average twice the cost of transportation by TAGS, since the former charges the cost of gas conditioning (Exhibit IV-8). While raw gas can be used directly by the methanol and electricity generating plants, conditioning would be required for utility sales to residential/commercial customers.

On balance, serving Fairbanks by constructing a lateral line to tap either TAGS or ANGTS appears more economical than constructing a small-diameter dedicated pipeline; while ANGTS is a relatively high-cost delivery system, no additional cost would be required to render gas of saleable quality for distribution through a utility grid. However, a small-diameter pipeline should be considered if TAGS or ANGTS are delayed, and gas is sought for Fairbanks. Moreover, constructng a line to Fairbanks -- particularly if over-sized to accommodate the gas volumes envisioned by the larger-scale projects -- could stimulate completion of either option, by reducing the financing needs -- and financing risks -- of these projects.

Exhibit IV-7

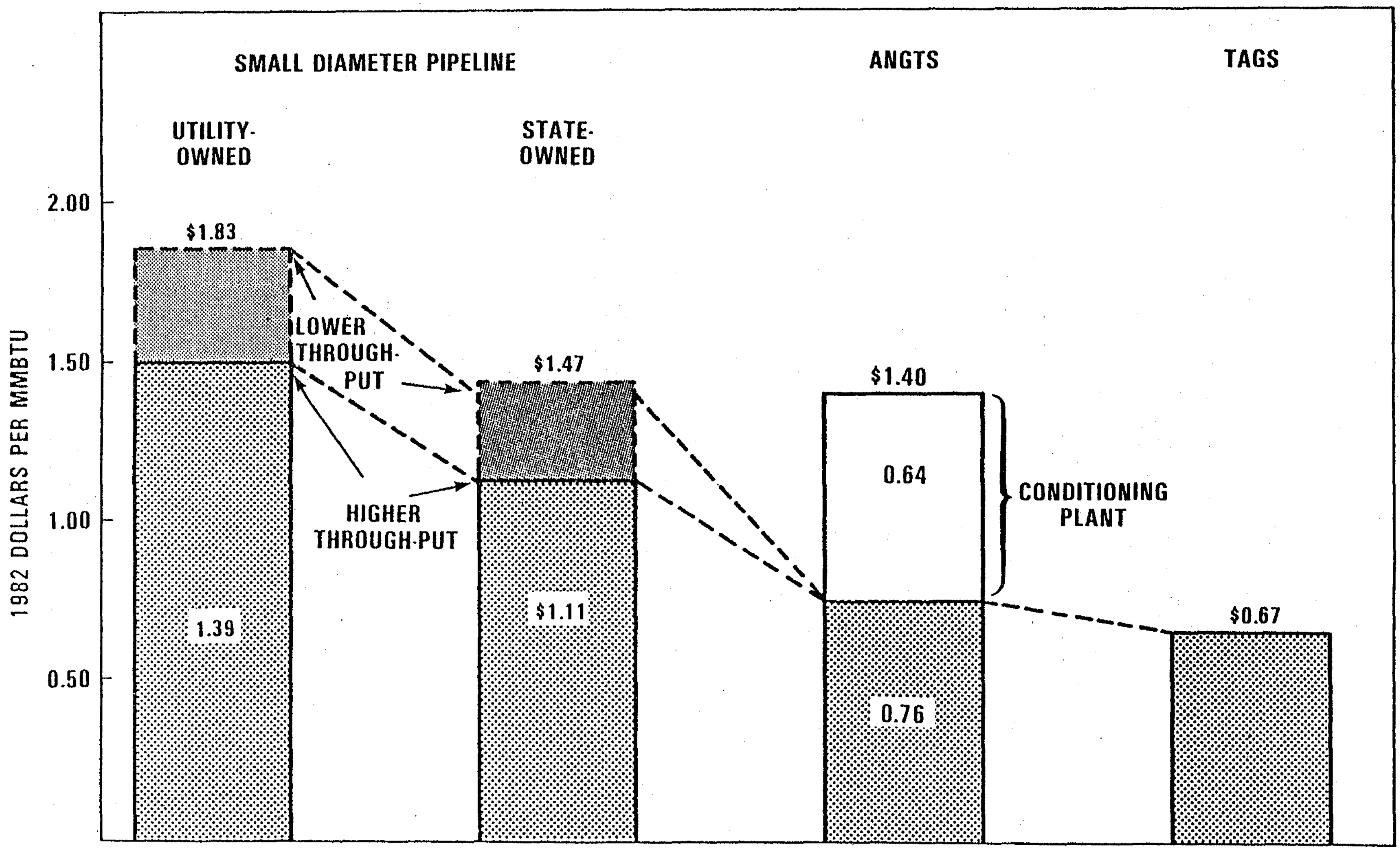
ANNUAL TARIFF CHARGES FOR GAS TRANSPORTED TO FAIRBANKS BY PIPELINE ALTERNATIVE




NOTE: EXCLUDES COST OF GAS USED AS COMPRESSOR FUEL.

Exhibit IV-8

COMPARISON OF TARIFF COST COMPONENTS FOR FAIRBANKS GAS DELIVERIES
BY PIPELINE ALTERNATIVE




NOTE: EXCLUDES COST OF GAS USED FOR COMPRESSOR FUEL.

### (3) Of the Utilization Options Proposed in the Fairbanks Area, Electricity Generation has the Lower Gas Conversion Costs

For the two projects proposed in Fairbanks -- using natural gas as a feedstock for methanol, or as a fuel for electricity generation -- capital costs and hence per unit operating costs were estimated in a range as set out on Exhibit IV-9. The range of high and low costs for the methanol plant -- supplied by the project sponsor, Alaska Interior Resources -- encompasses the range of likely actual plant costs; a more precise estimate of plant costs is precluded under the project sponsor's licensing agreement with the technology vendor. The range of costs for the electricity generation facilities reflects the low and high demand projections respectively. The generating facilities further benefit through a lower cost of capital for project financing. Since the plants would be part of a publicly-owned utility system, the State of Alaska's cost of capital was used. This cost of capital on both a real and nominal basis is substantially lower than the weighted average cost for all other projects. Exhibit IV-10 depicts operating cost components -- exclusive of gas costs -- for these two projects on average for operations through 2010. As can be seen on the exhibit, in the initial year of operation, the electric utility plant is approximately \$2.33 - \$3.20/MMBtu less expensive than the methanol plant; the average cost over the forecast period is similarly lower for the electricity plant, by \$0.83 - 1.27/MMBtu.

Additional transportation costs are associated with both projects. In the case of electricity generation, transmission and distribution losses must be accounted for; these have been estimated at 7.5% of generation output, and are included in the project cost estimates.* In the case of the methanol plant, transportation costs are incurred for rail shipment to Seward, Alaska, and then by tanker to either Asian Pacific Rim markets -- primarily Japan as targeted by the project sponsor -- or to the U.S. West Coast. As can be seen on Exhibit IV-10, rail transportation costs averaging 81¢ per MMBtu is an appreciable portion of the total methanol project costs. The major components of the rail transportation cost are:

- Tankcar leasing costs which, according to a potential lessor GATX (General American Transportation Corp.) are likely to remain at 1982 levels in real terms
- Tariff charges of the Alaskan Railroad are likely to decline slightly in real terms throughout the forecast period.**

Methanol might also be transported from Fairbanks through the TAPS crude oil line, for export through Valdez. This appears to be a less attractive option than rail shipments, given

- Possible difficulty in securing transport (e.g., need for segregated batch shipments, need to secure space from owner/shippers, etc.)
- Current tariff levels (estimated at \$3/bbl on the basis of shipping distance from Fairbanks to Valdez) which--at \$1.10/MMBtu--are higher than rail costs.

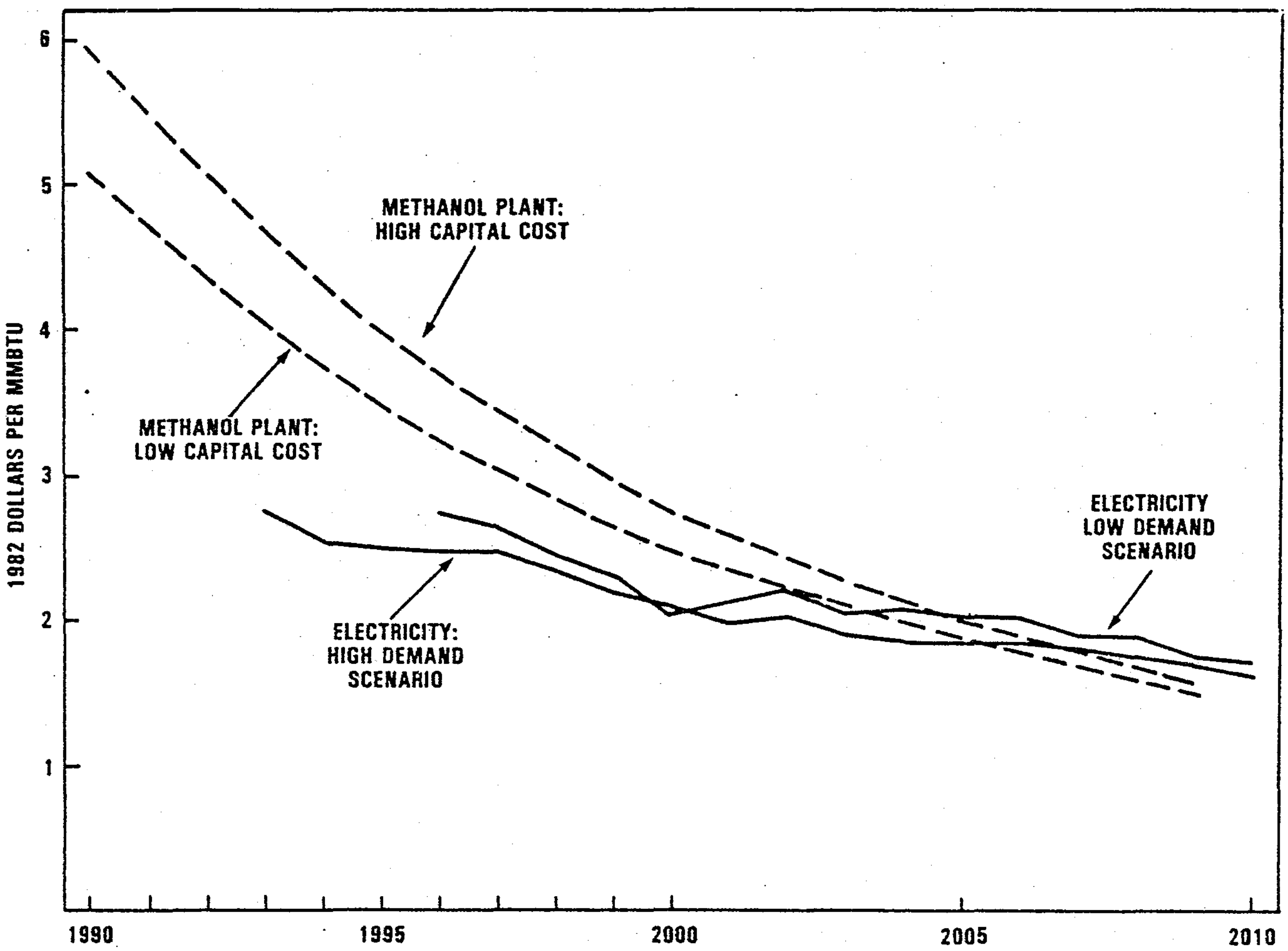
---

*Actual transmission and distribution losses may be higher, depending upon transmission distance and customer sales mix. At higher loss levels, revenue requirements and per unit generating costs would be higher than those shown on the exhibit, and would imply a lower gas netback value than that estimated in this chapter.

**The Alaskan Railroad tariff charge reflects savings extended shippers using new, shipper-supplied rail cars; an even lower tariff might be negotiable for bulk shipments.

Exhibit IV-9

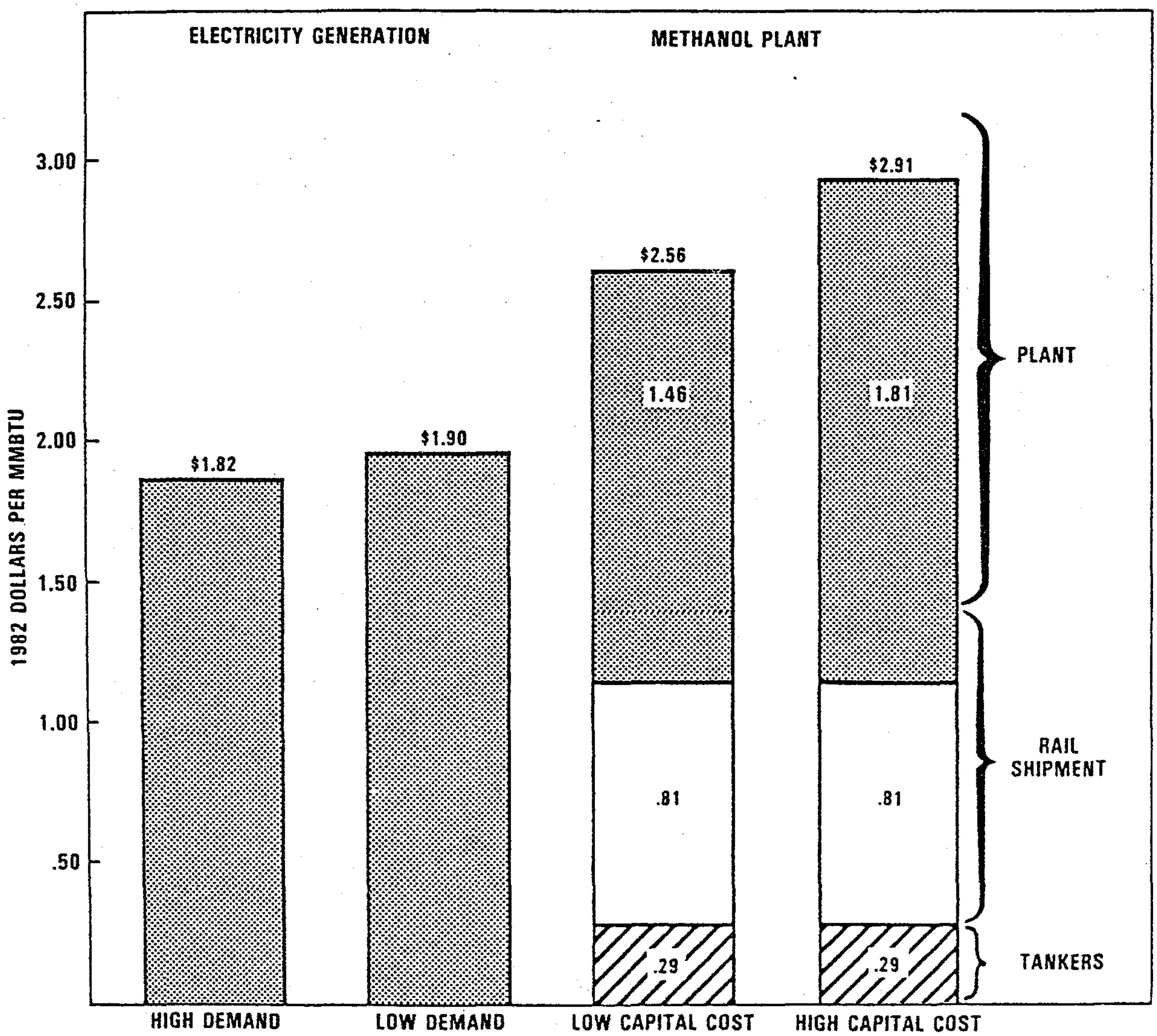
ANNUAL OPERATING COSTS FOR THE FAIRBANKS METHANOL AND ELECTRICITY GENERATING PLANTS




NOTE: EXCLUDES COST OF GAS USED AS COMPRESSOR FUEL.

Exhibit IV-10

COST COMPONENTS FOR THE FAIRBANKS-BASED PROJECTS AVERAGED OVER PLANT OPERATING LIFE




NOTE: EXCLUDES COST OF GAS FOR FUEL OR FEEDSTOCK.

## 2. THE TAGS AND ELECTRICITY GENERATION PROJECTS PROVIDE THE HIGHEST WELLHEAD VALUES FOR NORTH SLOPE GAS

Subtracting each project's annualized transportation and processing costs from the market clearing -- or competitive -- price in the targeted markets (described in Chapter III) yields the market value of North Slope gas at the wellhead. When applying this "netback wellhead" valuation approach, the cost of gas shrinkage through conversion losses and/or compressor fuel use serves to reduce the wellhead gas value.

From this analysis, TAGS and the electricity generation were found to yield the highest wellhead gas values of the four projects under consideration. These two projects also provide positive wellhead values sooner than the other options. For the two Fairbanks projects proposing to utilize ANS gas, evaluation was conducted on:

- The maximum gas cost each could afford to provide a price-competitive product
- The effect on product price of a gas purchase price equaling the royalty value accruing from the TAGS or ANGTS projects.

The following sections amplify upon these findings.

### (1) At LNG sales volumes envisioned under Phase III, TAGS provides a higher wellhead value for North Slope gas than does ANGTS

Exhibit IV-11 depicts the netback value of North Slope gas as delivered to the targeted end-use markets through the ANGTS and TAGS systems, respectively. These netback prices are arrayed in both the initial year of operation and on average over the forecast period, and shown separately under the three primary price scenarios.

As shown on the exhibit, ANGTS results in a negative wellhead value in the initial year of operation under all three price cases. Assuming initial deliveries in 1990, ANGTS provides positive wellhead values in 1995 in the "weaker economy" case, by 1996 in the "flat prices" case, and by 1992 in the "stronger economy" price case. With respect to the TAGS system, project transportation and processing costs also initially exceed LNG market prices as projected under the three price cases during Phase I operations; when Phase II is initiated, the higher system through-put relative to costs results in lower per-unit costs, and thereby positive wellhead values for the Alaskan gas.

The netback prices shown on Exhibit IV-11 reflect the "baseline" cost assumptions for TAGS and ANGTS. Exhibit IV-12 presents initial year netback values under the alternative costs developed in the sensitivity testing; end-use market values under the "weaker economy" price scenario were employed for purpose of this comparison. In the two most comparable cost case alternatives -- "baseline costs" and "baseline costs with accelerated depreciation" -- TAGS provides a less negative initial year wellhead value and the earliest reversal to positive value. Under any alternative, TAGS provides a positive wellhead value as early -- if not earlier -- than ANGTS.

Exhibit IV-11

NETBACK WELLHEAD GAS VALUES FOR THE TAGS AND ANGTS SYSTEMS

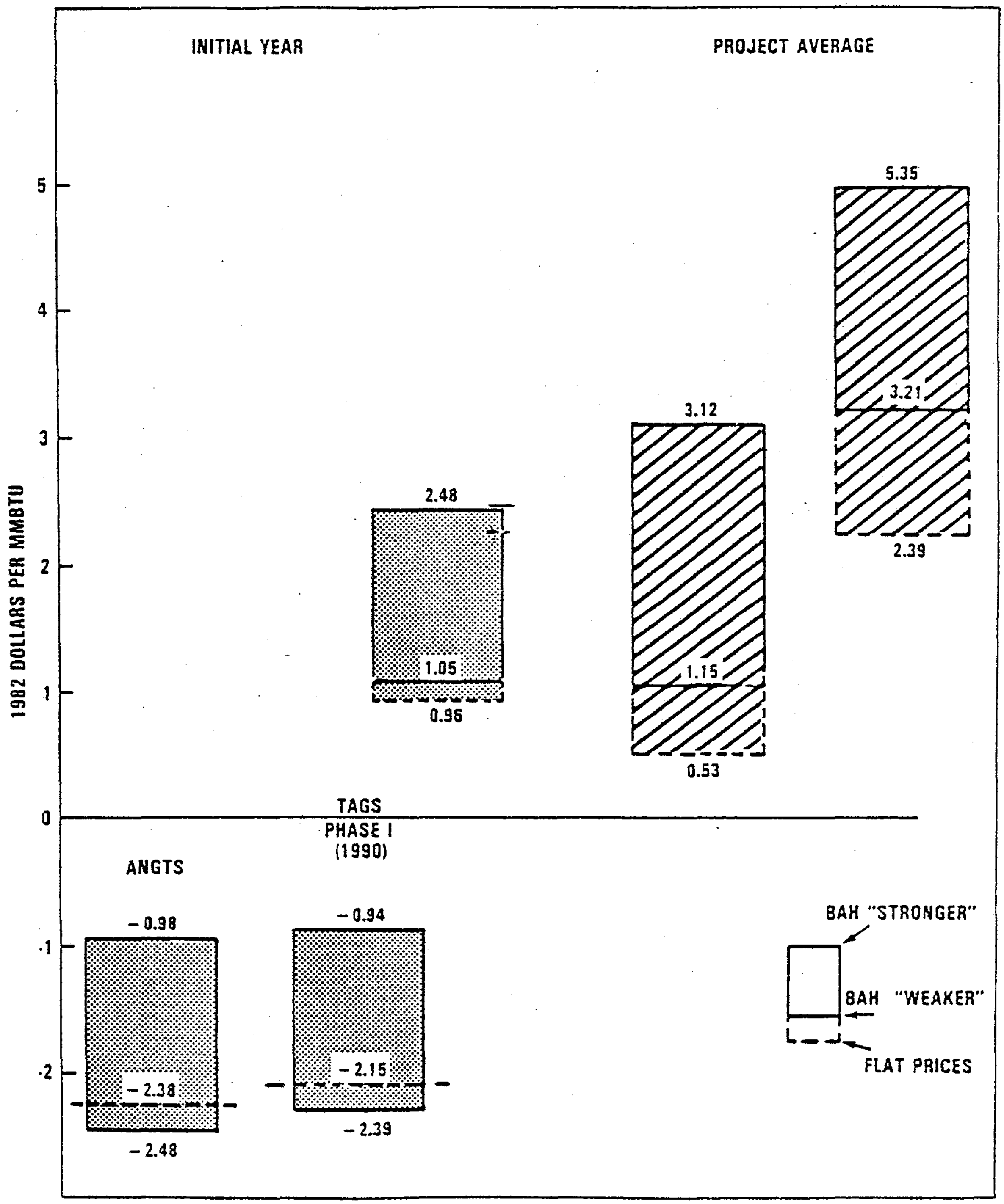
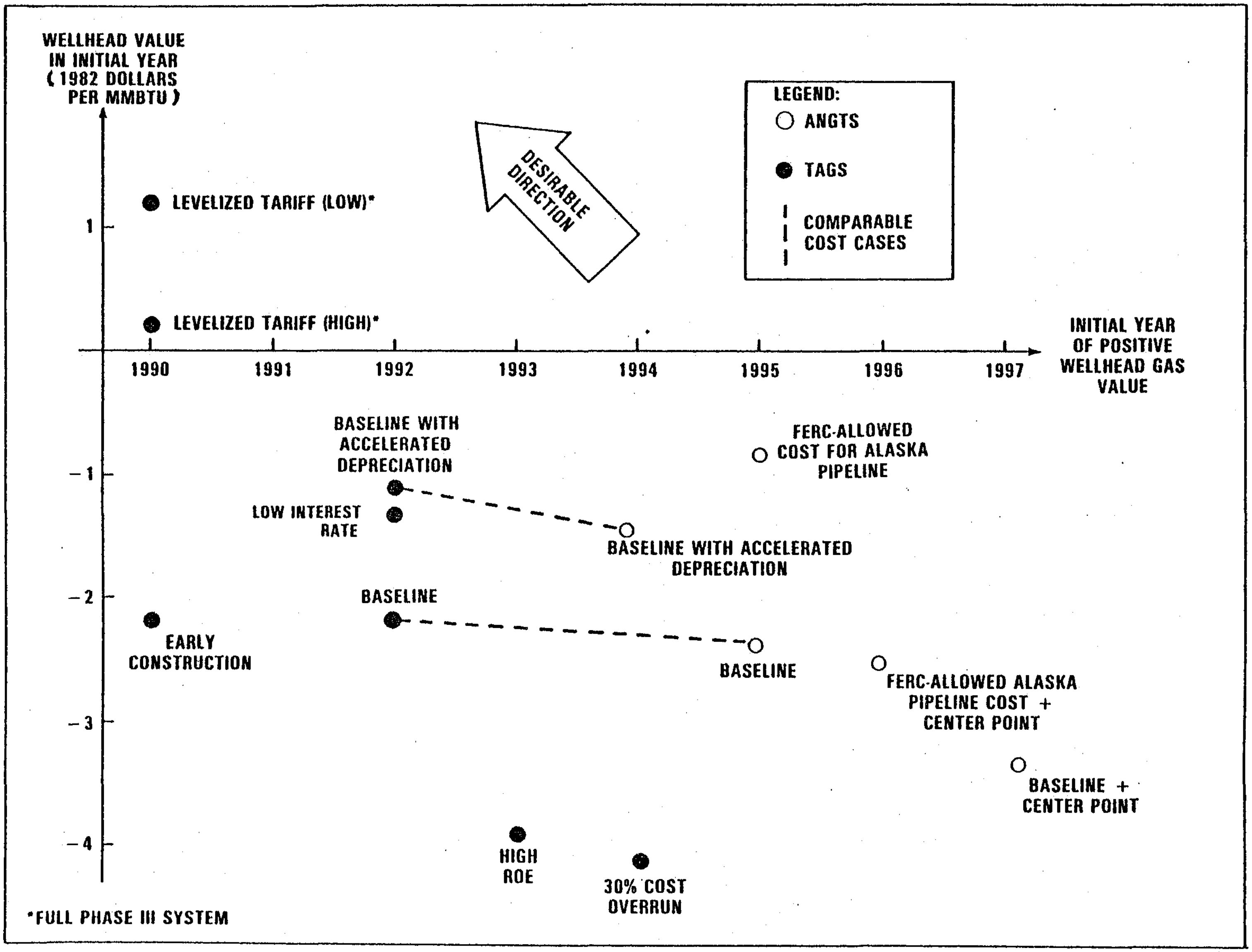


Exhibit IV-12

WELLHEAD GAS VALUE IN THE INITIAL PROJECT YEAR AND DURATION OF NEGATIVE WELLHEAD VALUE UNDER SENSITIVITY TESTS ON TAGS AND ANGTS




NOTE: EXCLUDES COST OF GAS USED FOR COMPRESSOR FUEL. NETBACK VALUE BASED ON "WEAKER ECONOMY" CASE.

(2) **Of the Fairbanks-based projects, the electricity generating plants can afford a higher city gate — and wellhead — gas price than can the methanol plant.**

Exhibit IV-13 depicts the netback value of Alaskan gas at the Fairbanks city gate for two Fairbanks-based projects; Exhibit IV-14 presents the netback value to the North Slope wellhead for each project, under the three transportation options. For each option, netback prices are shown at the two project cost ranges:

- Low and high capital costs, for the methanol plant
- Low demand (lower capacity additions) and high demand, for the electricity plants (although initial operation varies by demand scenario, the size and cost of the initial plant addition is the same under each).

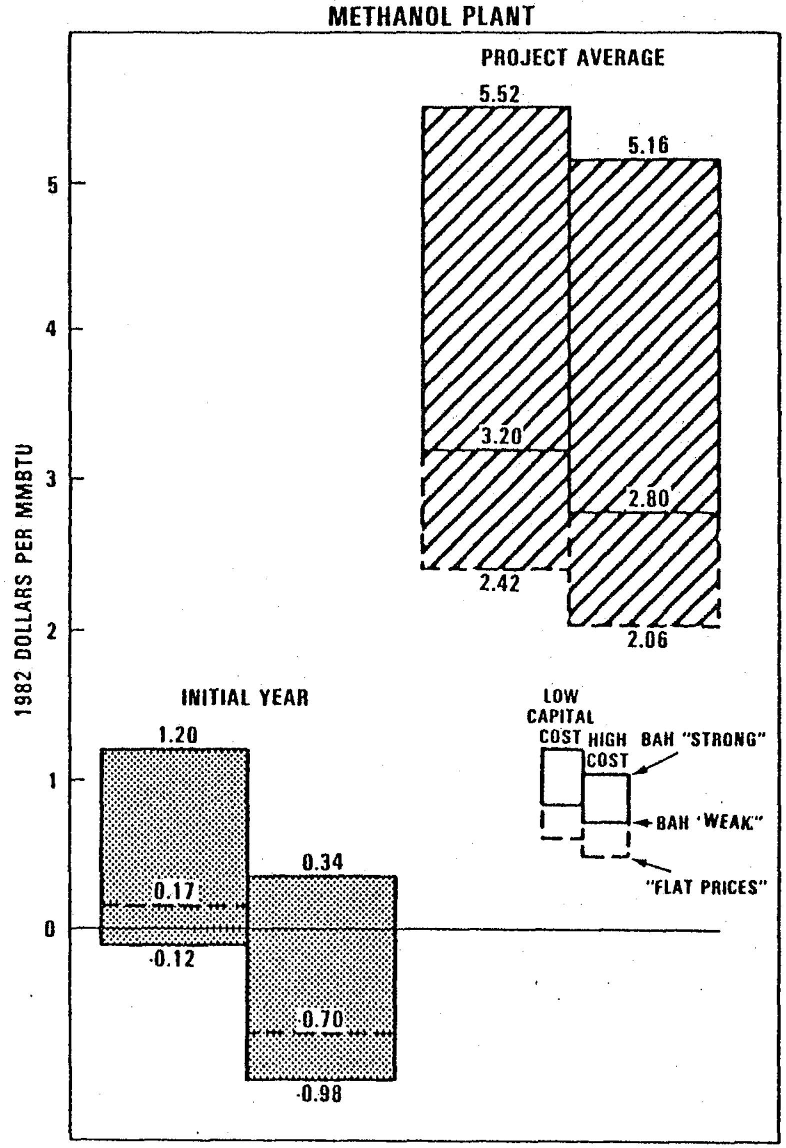
On Exhibit IV-13, maximum affordable city gate gas prices are shown in a range for the methanol plant which reflect the three oil price cases; for the electricity plant, maximum affordable prices equate to the electricity prices discussed in Chapter III.

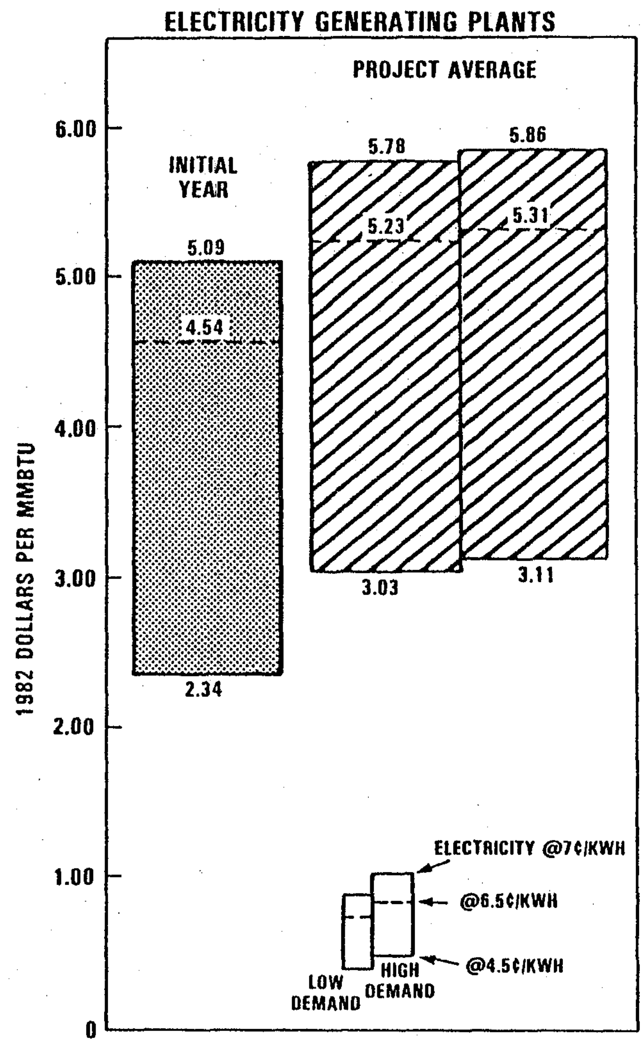
As shown on Exhibit IV-13, the maximum affordable gas price for the methanol plant is, in some cases, negative in the initial year, these values turn positive by 1993, or the third year of operation. Use of a different base for retail prices tends to obscure the advantage of the electricity option over the methanol plant; as against "weaker economy" price case, retail electricity prices could be as low as 2.4¢/kWh (in 1982 dollars) and yield a maximum city gate gas cost equal to that of the methanol plant.

Not surprisingly, then, the electricity option yields the highest wellhead netback price, regardless of transportation method, as shown on Exhibit IV-14.

Exhibit IV-13

MAXIMUM AFFORDABLE CTY GATE GAS PRICE FOR THE FAIRBANKS METHANOL PLANT AND ELECTRICITY GENERATION PROJECTS

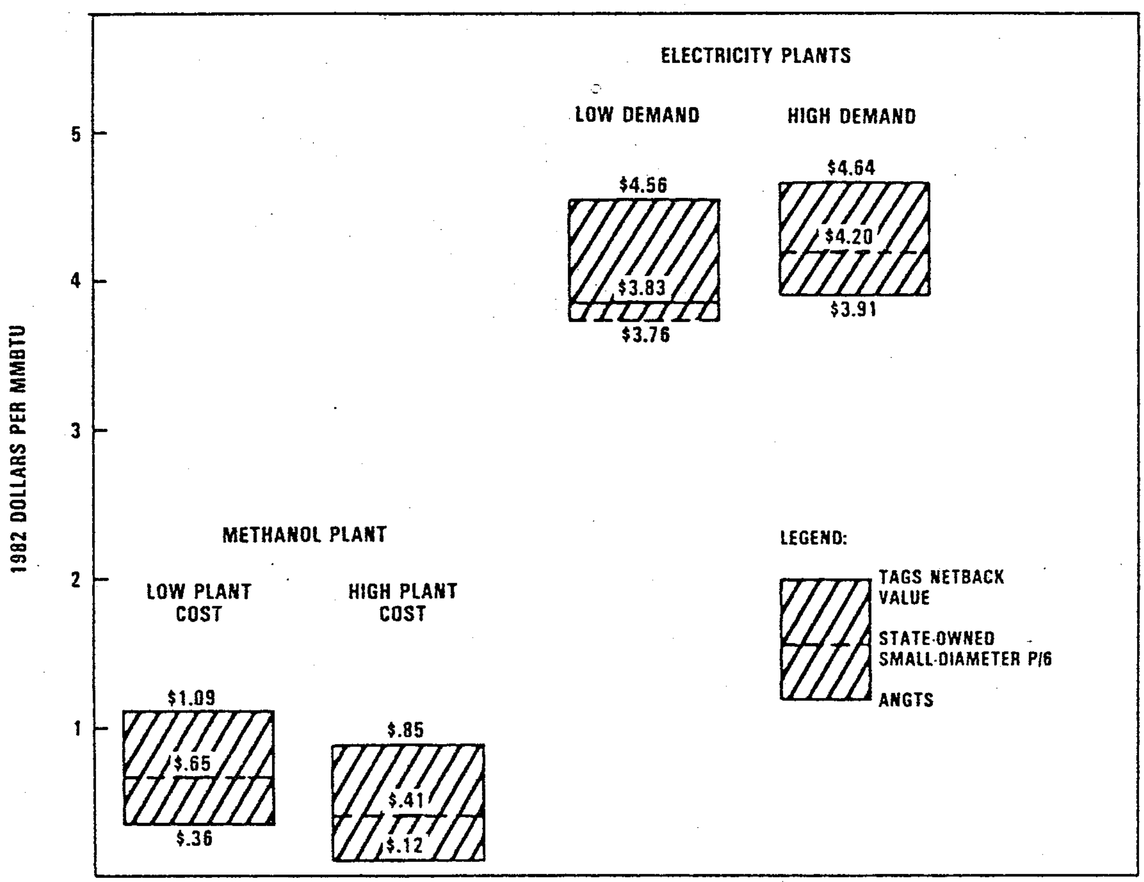



NOTE: EXCLUDES COST OF GAS FOR FUEL OR FEEDSTOCK.

Exhibit IV-14

NETBACK WELLHEAD GAS PRICE FOR THE FAIRBANKS-BASED PROJECTS




NOTE: EXCLUDES COMPRESSOR FUEL COST. HIGH THROUGHPUT LEVEL USED FOR STATE-OWN PIPELINE DELIVERIES TO METHANOL PLANT; LOW OR HIGH THROUGHPUT USED FOR ELECTRICITY PLANT DELIVERIES, ACCORDING TO DEMAND LEVEL.

# V. ANALYSIS OF IN-STATE BENEFITS

The benefits to the State from development of North Slope gas reserves by the alternative proposals can be estimated from gas wellhead value and project costs. This analysis incorporates the following elements:

- **Value-added** to the State, including:
  - Royalty payments accruing to the State
  - State severance taxes on the gas produced
  - State income and property taxes paid by with the various projects.
- **Other in-state benefits and impacts,** including:
  - Infrastructure development needed by -- or provided by -- the resource development options
  - Socio-economic and environmental impacts from the proposed projects, including employment benefits.

## I. STATE VALUE-ADDED IS HIGHEST UNDER THE TWO LARGE-SCALE OPTIONS; HOWEVER, THE FAIRBANKS-BASED PROJECTS ALSO CONTRIBUTE IMPORTANT VALUE TO THE STATE

In order to compare the projects proposing to utilize the North Slope gas,* State value-added has been confined to quantifiable tax and royalty payments, identified on Exhibit V-1. As suggested on the exhibit, the value-added amount reflects:

- Project costs -- construction and required return on equity -- which in turn affect the level of property and State income tax payments
- Netback wellhead gas value, which determines royalty and severance tax payments.

Project size -- measured by capital cost and gas production requirements -- is also a significant determinant; for example, a project using half as much gas as another option would need to yield twice the wellhead gas value to produce equal royalty and severance tax revenues. By virtue of their substantially larger scale, the two gas transportation options -- TAGS and ANGTS -- provide State and local revenues which are 8-12 times greater than the two smaller-scale options combined. Nonetheless, these Fairbanks-based projects can contribute State and local tax revenues (and other less quantifiable value to the State economy), which make them potentially valuable additions to the State industrial base.

*For the EOR option, State value-added would incorporate quantity of incremental oil recovery and the wellhead oil value in determining the revenue stream from State severance taxes and additional royalty payments. Due to uncertainties over the likely volume of incremental production, value-added analysis was not extended to this project.

Exhibit V-1

APPROACH IN DERIVING STATE VALUE-ADDED FROM NORTH SLOPE GAS DEVELOPMENT

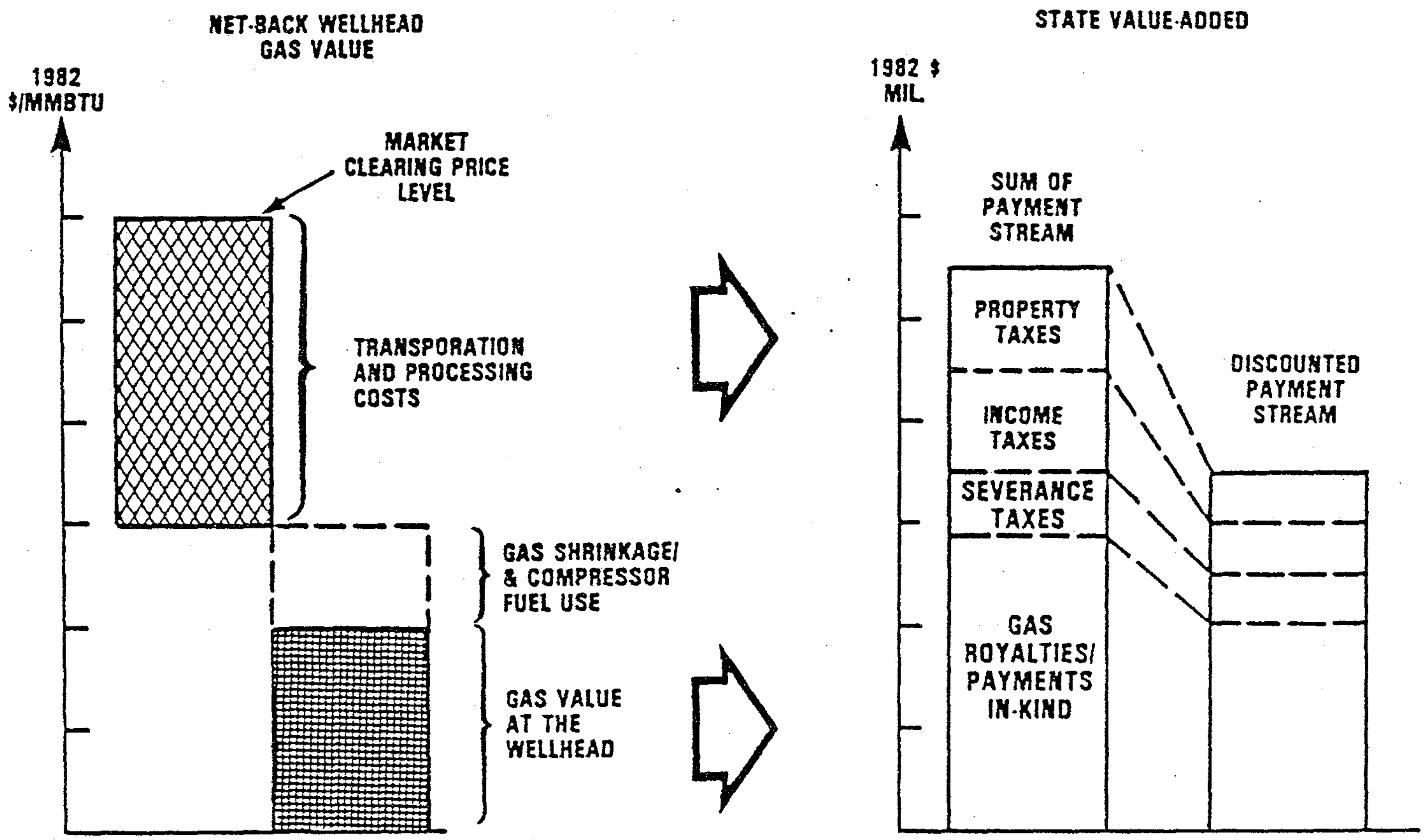
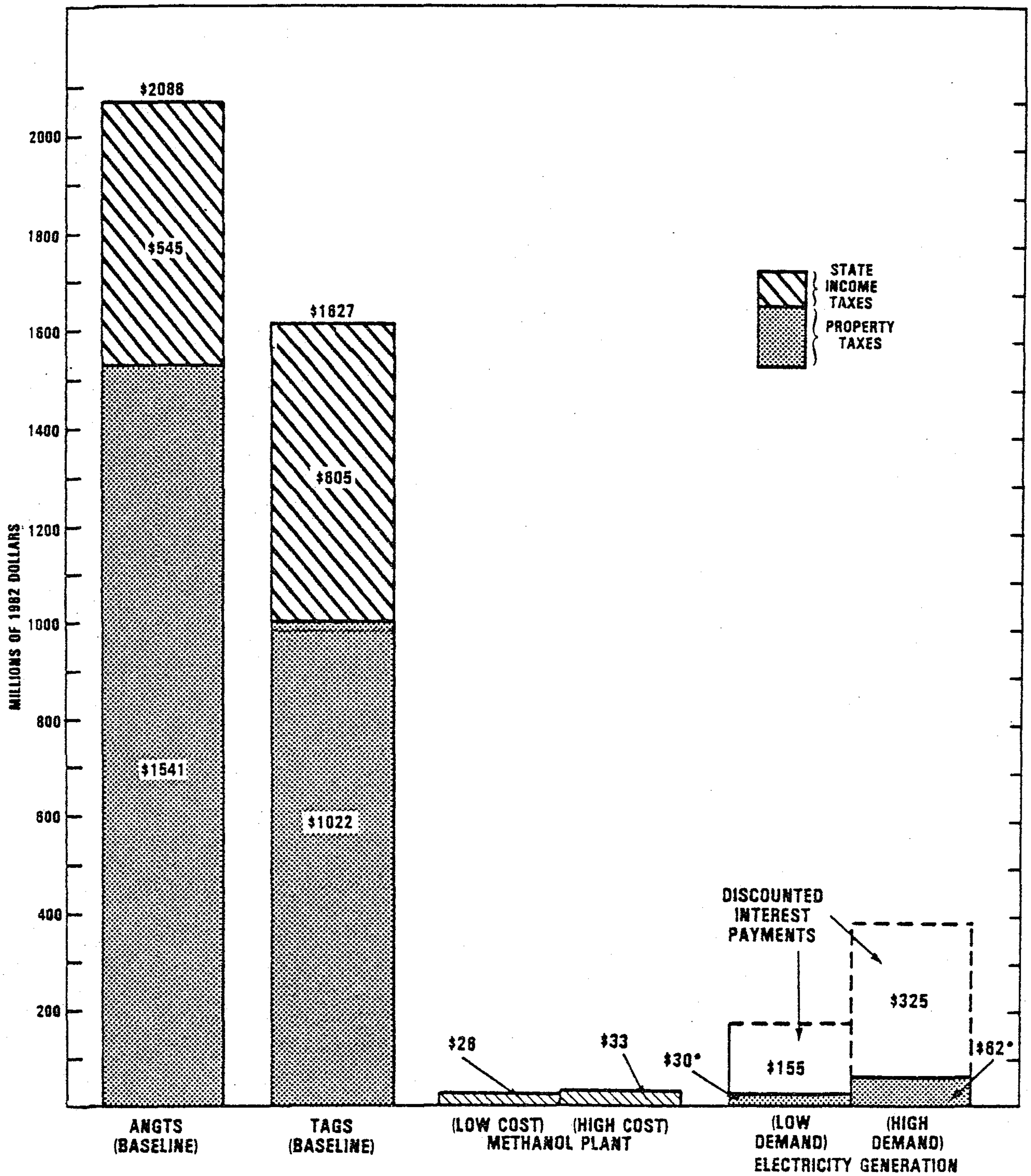


Exhibit V-2

NET PRESENT VALUE OF INCOME AND PROPERTY TAX PAYMENTS FOR THE PROJECTS EVALUATED




*PAYMENTS IN LIEU OF PROPERTY TAXES

NOTE: "NET PRESENT VALUE" REFERS TO CUMULATIVE PAYMENTS, DISCOUNTED TO 1982 DOLLAR BASIS USING STATE'S COST-OF-CAPITAL.

Project cost and operating assumptions as supplied by project sponsors has been used in this analysis; actual construction cost and operating expense and conditions could vary markedly from these estimates. As a cautionary note, therefore, the value-added amounts provided below should be considered projections and subject to uncertainty.

(1) The two large-scale transportation options -- TAGS and ANGTS -- could provide income and property tax revenues amounting to $1.6-$2.1 billion

Project capital costs determine local property tax and state income tax revenues obtainable from each project.

- **Property taxes** are assessed directly on project book value (i.e., construction cost less depreciation)

- **State income tax** levels can be ascertained from after-tax income requirements, in which in turn are a function of

  - Required return on equity (ROE)
  - Amount of equity investment.

The "baseline case" capital costs of the Alaskan segments of the TAGS and ANGTS projects -- amounting to slightly over $14 billion for each (in 1982 dollars,* exclusive of financing costs) -- dwarf the capital costs associated with the two Fairbanks-based options. Not surprisingly, then, these tranportation systems provide substantially greater tax revenues, as shown on Exhibit V-2. In deriving these revenue streams

- Annual payments were discounted at the State's cost-of-capital, and summed over the 20 year period 1990-2009 (with 14-17 years used for the electricity option in accord with its operation schedule)

- Property taxes were assumed at 2% of book value except where project sponsors have identified lower jurisdictional rates (i.e., 40 mills per $1000 book value for the methanol plant at Fairbanks, and 0.4% on book value for the TAGS liquefaction plant)

- State income tax rate of 9.4% -- a rate suggested by project sponsors -- was applied to pre-tax income.

To reflect the time-value of the revenue streams, tax and royalty receipts have been discounted using the State's assumed cost of capital -- 10.5% in nominal terms, or 3.5% real.

As shown on the exhibit, the discounted sum of TAGS' property taxes is $500 million less than ANGTS, due to its lower and phased construction expenditures and lower borough taxes (on nearly one-third of total project costs); however, TAGS' greater return on equity requirement (ROE at 18% versus 14-16% for ANGTS) results

*Throughout this chapter, all dollar amounts are stated in constant 1982 dollars unless otherwise referenced.

payment. Local property tax payments by the methanol plant are negligible -- totaling approximately $50,000 (on a discounted basis) in both plant cost cases. The electricity generation plants -- presumed owned and operated by a State power authority -- are exempt from local, state or federal taxes; however these plants make "payments in lieu of taxes" (a common practice for publicly-owned utilities) in an amount equal to the 2% property tax level. Also shown for this project are interest payments amounting to $155-$325 million; if the plants were financed through general State revenues -- rather than a bond issue -- this amount could accrue to the State or could be eliminated from the project's revenue requirements and thus reduce electricity rates.

(2) **Because of its higher wellhead gas value, TAGS provides greater severance tax and royalty payments than ANGTS**

The size of severance tax and royalty revenue income streams to the State is based upon:

- **Volume of gas utilized** -- which is project-determined
- **Netback wellhead gas value** -- which is market-determined.

Elapsed time before positive wellhead value is achieved also affects severance taxes, by holding such payments to a minimum during the term of negative wellhead value (i.e., 6.4¢/Mcf currently, which, although held constant in nominal dollars by law, we increased with inflation during the forecast period to reflect possible future updating).

While TAGS proposes to utilize a somewhat greater volume of gas than ANGTS (847 Bcf/yr *at full operation, versus 766 Bcf/yr for ANGTS), this project's apparent ability to yield a higher netback gas value is the major reason for the higher tax and royalty payments available through this option. As shown on Exhibit V-3, TAGS provides severance tax payments which are $773 million to $965 million greater than ANGTS in all three price scenarios. ANGTS is also disadvantaged by its longer period of negative wellhead value (up to 6 years in the "flat prices" case). By contrast, wellhead prices for TAGS turn positive in its third year of operation, using "baseline" capital costs; during the period of negative wellhead values, TAGS' flow rate is much lower (277 Bcf/yr), which further minimizes the opportunity cost to the State from minimal tax payments.

The higher wellhead value under TAGS similarly results in higher royalty payments, as depicted on Exhibit V-4. In the three price cases tested, the State would secure revenues which are $1.9-2.1 billion greater (on a discounted or net

*The volume shown represents the portion of raw gas flow necessary to support the LNG export project. The ANGTS volume is conditioned gas (i.e., after $CO_2$ removal and extraction of natural gas liquids). These flow rates were used in computing the severance tax payment, since gas usage on the leasehold -- presumed to extend to conditioning use on the Slope -- is presently exempt from taxation.

Exhibit V-3

NET PRESENT VALUE OF SEVERANCE TAX PAYMENTS BY TAGS AND ANGTS

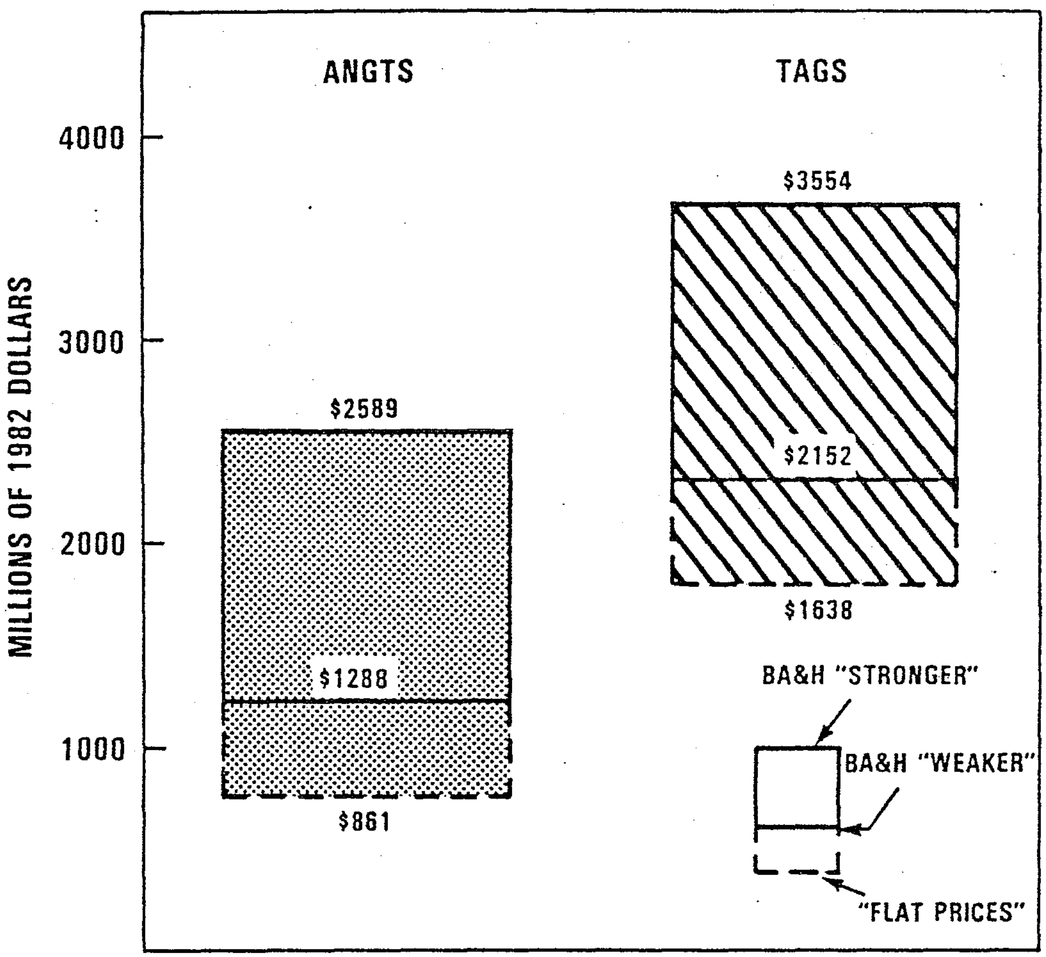
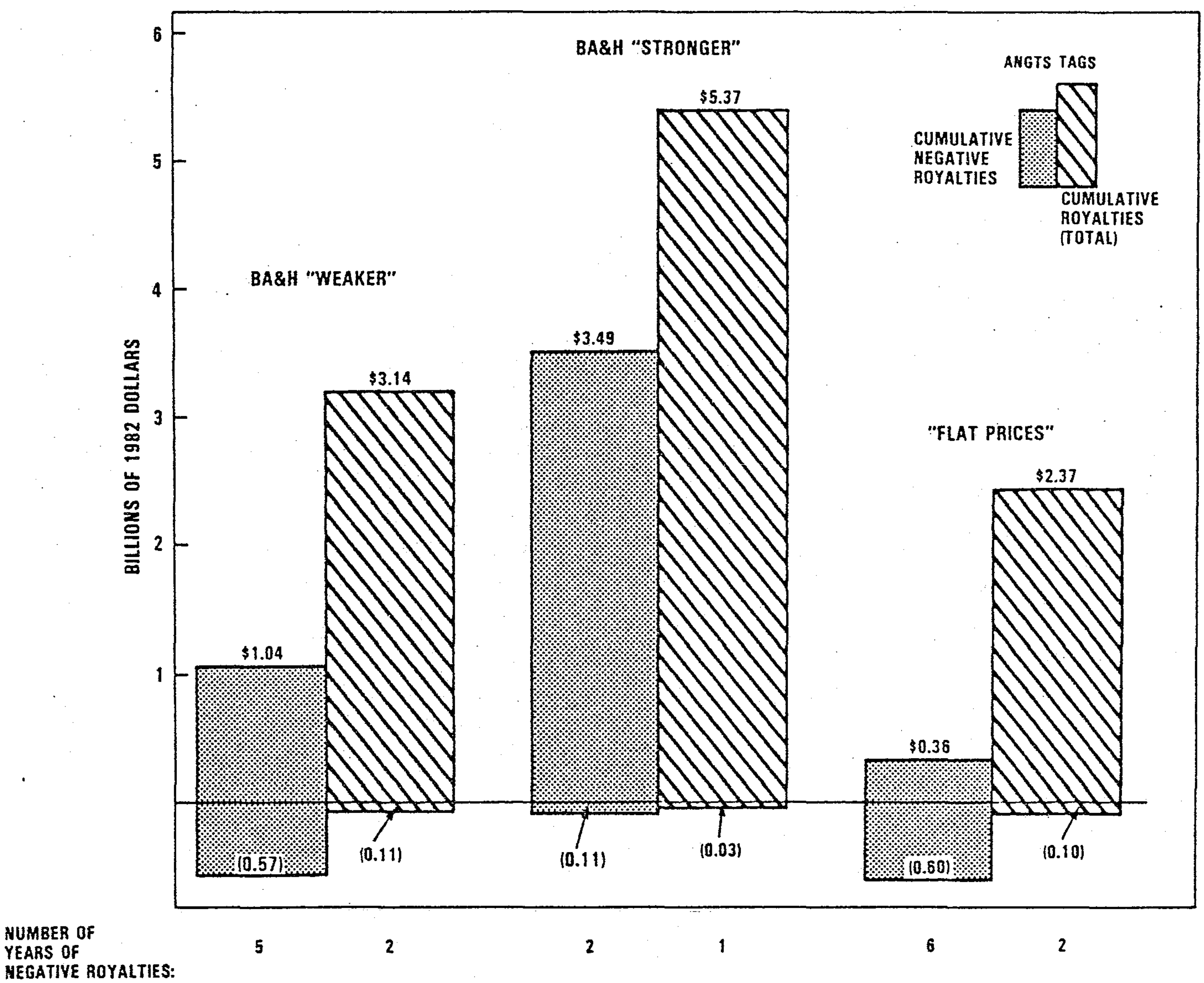


Exhibit V-4

NET PRESENT VALUE OF ROYALTY PAYMENTS BY TAGS AND ANGTS



present value basis) by selling its royalty gas to TAGS for LNG export. The royalty payments shown on the exhibit assume that the State's royalty interest gas represents one-eighth of the project's gas requirements in all years of operation; as a consequence, when the gas wellhead value is negative the State is in effect providing a "subsidy" to the project, in an amount shown "below the line" on the exhibit. The size of this subsidy is particularly large for ANGTS in the "weak economy" and "flat prices" scenarios. If the State were to withhold its gas until positive value is attainable -- or sell its gas for a nominal amount (e.g., 10¢/MMBtu) -- higher royalty amounts than those shown on Exhibit V-4 could be obtained, but TAGS would still provide greater royalty payments than ANGTS.

(3) **While TAGS has the potential for greater State value-added than ANGTS, either project would be a significant source of State reveues**

Due to its larger royalty and severance tax payments, the cumulative discounted revenue stream generated by TAGS is approximately $2.3-2.5 billion more than that for ANGTS, under the three price scenarios. Because project capital costs can affect the timing and size of value-added receipts, the results obtained using "baseline" project costs were tested against alternative annual operating costs derived from the sensitivity cases. As shown on Exhibit V-5, if Federal income tax savings arising from accelerated depreciation were used to lower tariff charges -- and thereby raise the gas netback value -- royalty and severance tax payments would increase by $260 million for ANGTS, and by $310 million for TAGS, in the same price case ("weaker economy").

The exhibit also demonstrates the effect of the trade-off between these revenue streams from higher project costs.

- Under the risk contingency -- and higher construction cost -- projected by the ANGTS sponsors ("current filing plus center point"), income and property tax payments increase by $460 million in total over baseline levels; however, the ensuing lower wellhead gas value reduces cumulative severance tax and royalty payments by $750 million.

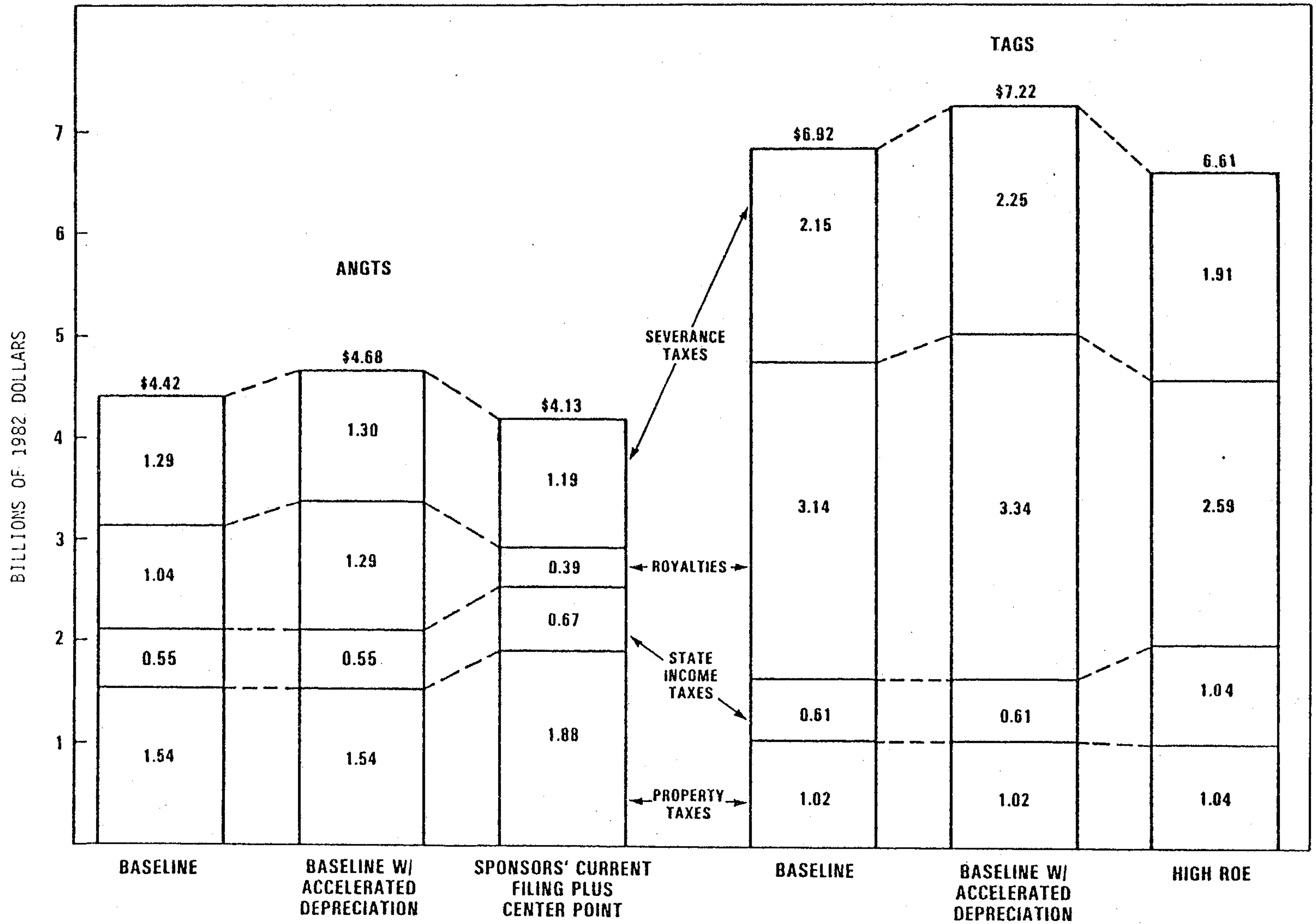
- If the TAGS equity participants obtain a 30% after tax return on equity (a level considered in that project's economic analysis), this higher cost would also be reflected in higher property and income tax payments. However, the increased receipts from these revenue sources -- $470 million in total -- are more than offset by the $790 million reduction in cumulative royalty and severance tax payments.

On balance, then, the State obtains the greatest value-added when project construction and operating costs can be held to a minimum.

To place these potential value-added revenues into perspective, Exhibit V-6 compares receipts from TAGS and ANGTS in 1998 with Alaska Department of Revenue projections (published June 1982) of severance tax and royalty payments from oil production for that year. TAGS and ANGTS revenues include income and property taxes, amounting to $156 and $159 million, respectively in the "baseline" cost case. As shown on the exhibit, under the "weaker economy" price scenario, TAGS could add approximately $649 million in State receipts while ANGTS could produce $355 million -- increases of 74% and 41%, respectively, over State severance

Exhibit V-5

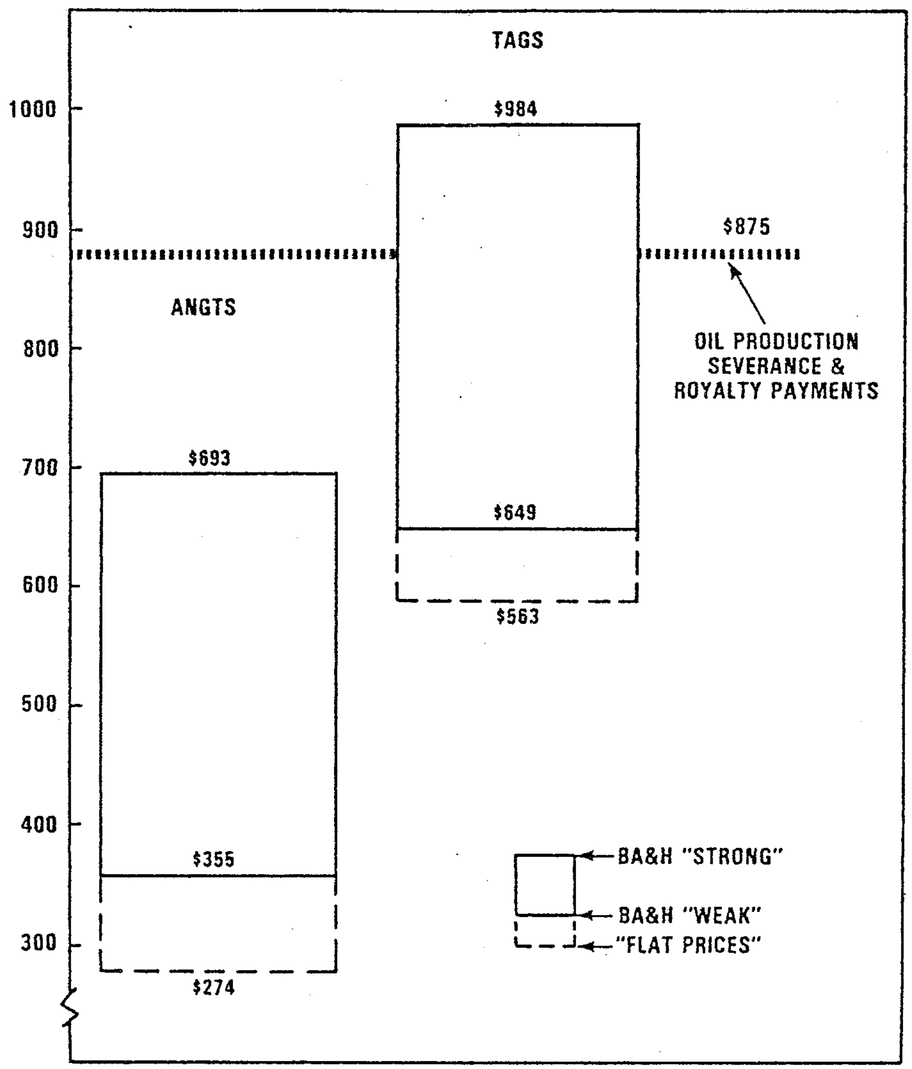
STATE VALUE-ADDED FROM TAGS AND ANGTS UNDER ALTERNATIVE PROJECT COST CASES




IOTE: AMOUNTS SHOWN REPRESENT "NET PRESENT VALUE" OF PAYMENTS (I.E., CUMULATIVE PAYMENTS DISCOUNTED TO 1982 DOLLAR BASIS, USING THE STATE'S COST-OF-CAPITAL).

Exhibit V-6

# 1998 PROJECTED STATE REVENUES FROM TAGS OR ANGTS COMPARED WITH PETROLEUM PRODUCTION TAXES




SOURCE: ALASKA DEPARTMENT OF REVENUE, PETROLEUM REVENUE DIV., PETROLEUM PRODUCTION REVENUE FORECAST, QUARTERLY REPORT (JUNE 1982); BOOZ, ALLEN & HAMILTON INC.

and royalty receipts from petroleum production. In short, revenues from development of the State's natural resources could be increased significantly by construction of either system.

(4) **Besides providing revenues which more than recoup the capital outlay, the Fairbanks electricity plants could provide high royalty payment revenues**

As shown on Exhibit V-2, constructing electricity generating plants at Fairbanks provide state revenues in the form of

- Payments in lieu of property taxes
- Interest payments if financed through general state revenues.

An additional source of State income would be repayment of the state funds borrowed. Exhibit V-7 compares these cumulative income streams with the amount of state funds needed to construct the plants under the "low" and "high" electricity demand scenarios. As the exhibit shows, by 2010 -- when the final plant is added -- cumulative receipts nearly equal capital outlay requirements at either demand level. By 2020, cumulative interest and principal payments exceed the amount of initial capital investment -- while the rate base is not fully depreciated.

Assuming the State were to use a portion of its royalty gas as fuel for electricity generation, the state has the option of valuing this gas (and therefore receiving income) equal to royalty price paid by either TAGS or ANGTS, or at some other value. Exhibit V-8 provides the discounted cumulative gas payments, at the royalty values obtainable under the "weaker economy" price case for TAGS and ANGTS. The greater gas usage under the high electricity demand scenario accounts for the higher gas payments over the low demand scenario. The lower gas netback value of ANGTS results in lower payments for royalty gas used for electricity generation. Concurrently, the retail electricity price is lower at the ANGTS royalty gas price -- reaching only 5.5¢/Kwh in 2010. Retail electricity prices equal 7.3¢/Kwh by 2010 at the royalty value achieved by TAGS; if the State chose to keep electricity prices at a maximum of 6.5¢/Kwh (the estimated price of hydroelectricity), then the payment shown for TAGS-delivered gas would need be reduced by $100,000-$150,000 in the low and high demand cases, respectively.

Exhibit V-8 also depicts the payments possible if gas were delivered though a State-owned, small-diameter pipeline. Under this option, the netback gas value was set at a level which supplies electricity of 6.5¢/Kwh, and results in gas payments amounting to $.7-$1.5 billion.

(5) **To be competitive in Japanese markets, the Fairbanks methanol requires a gas price which is lower than the wellhead gas value under TAGS or ANGTS**

Because of its higher transportation and processing costs, the Fairbanks methanol requires a low gas price to be competitive in Japanese markets. This "maximum affordable" gas price is shown on Exhibit V-9, and contrasted with the average wellhead value from the TAGS and ANGTS projects under the "weaker economy" price case. As can be seen on the exhibit, the State would, in effect, need to "subsidize" the methanol plant by receiving royalty payments at a price less than

Exhibit V-7

CUMULATIVE CAPITAL OUTLAYS AND STATE REVENUE INFLOWS FROM THE FAIRBANKS ELECTRICITY PLANTS

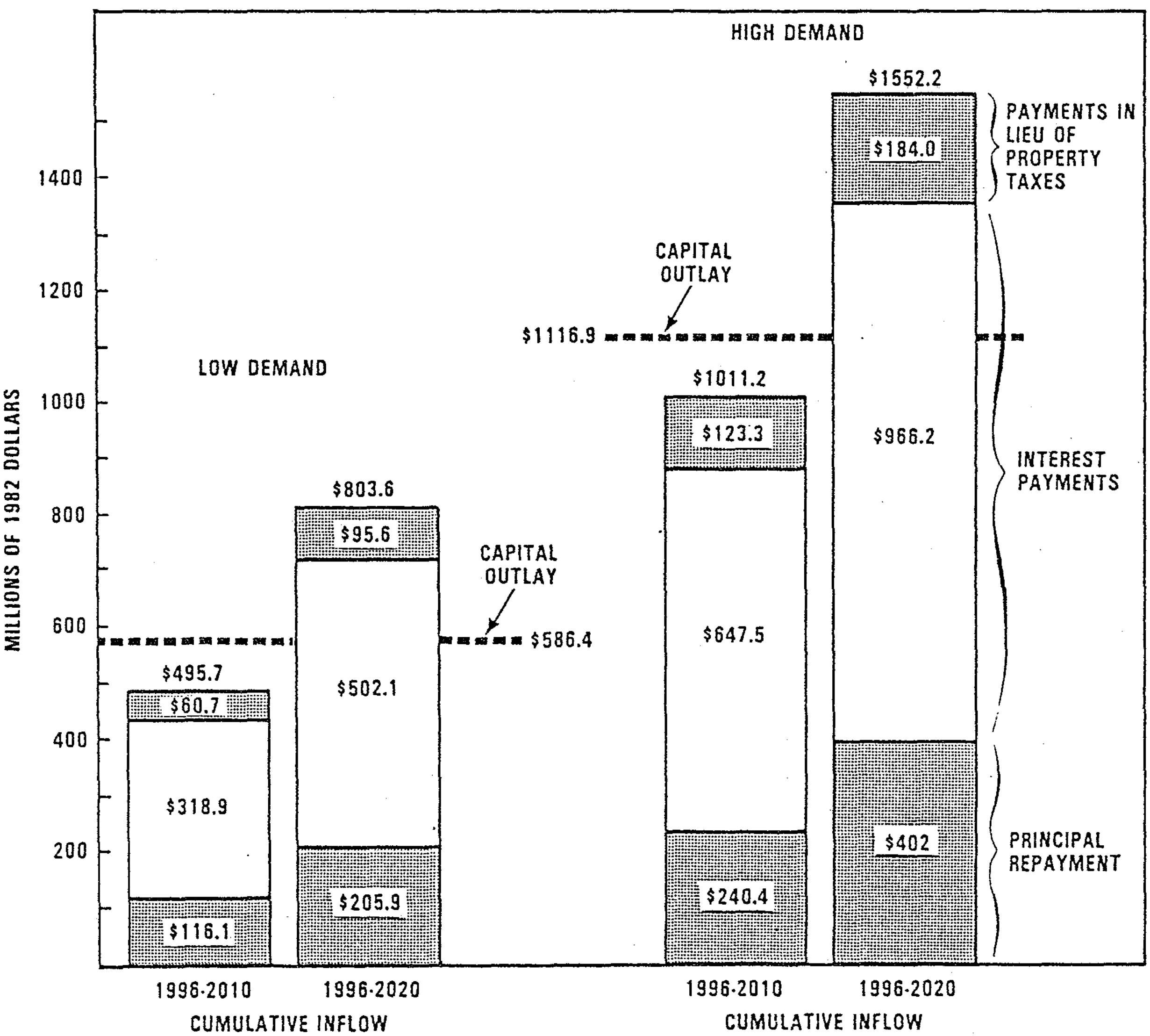


Exhibit V-8

STATE ROYALTY PAYMENTS FOR GAS USED FOR ELECTRICITY GENERATION UNDER (MILLIONS OF 1982 DOLLARS) ALTERNATIVE WELLHEAD PRICING LEVELS

| | LOW DEMAND | HIGH DEMAND |
|---|---|---|
| TAGS ROYALTY VALUE | $ 91.0 | $ 188.8 |
| ANGTS ROYALTY VALUE* | $ 49.9 | $ 104.7 |
| STATE-OWNED SMALL-DIAMETER PIPELINE** | $667.1 | $1523.0 |

* Under the "weaker economy" price case.

** Netback value with 6.5¢/kwh electricity price.

Exhibit V-9

ROYALTY VALUE OF GAS USED FOR METHANOL PRODUCTION (1982 $/MMBtu)

| | NETBACK WELLHEAD VALUE | METHANOL PLANT MAXIMUM AFFORDABLE GAS PRICE | |
|---|---|---|---|
| | | LOW PLANT COST | HIGH PLANT COST |
| TAGS | $3.21 | $0.99 | $0.75 |
| ANGTS | $1.15 | $0.25 | $0.03 |

could be received by sale to ANGTS or TAGS; indeed; if gas were delivered by ANGTS and the methanol plant cost $750 million to build, a **real** subsidy of 21¢/MMBtu would be required by plant sponsors to produce methanol at a competitive price for export to Japan.

2. GENERALLY, ALL FOUR PROJECTS PROVIDE AND/OR INDUCE IMPROVEMENTS TO THE STATE INFRASTRUCTURE

All four projects will add to the State's industrial base and thereby, the State's infrastructure. The socio-economic and employment impacts from the size and local of project expenditures is discussed in the concluding section of this chapter; summarized below are a few salient points concerning infrastructure contribution under the four projects.

(1) **Alaskan port development would be enhanced under the TAGS and methanol plant projects**

TAGS proposes LNG export through Cook Inlet, at a port site near Nikiski, on the Kenai Peninsula. These port facilities, estimated to cost $250 million, include channel dredging, docks and wharves, and other port improvements. Since these costs would be entirely assumed by the TAGS project, this further port development is an additional benefit to the State. If an alternative site were chosen (for example, the western side of Cook Inlet), this same intensity and kind of infrastructure development would occur, and might stimulate further economic activity.

The methanol plant sponsors anticipate methanol export through the port of Seward, at the terminus of the Alaskan Railroad. While the project cost estimates as supplied by the project sponsors have been increased to take into account the need for storage at the port, the sponsors have not expressed intentions to finance the port expansion (e.g., additional wharves or docks, etc.). To the extent that such additional facilities are necessary, this cost may be borne by the Port Authority of Seward; however, additional channel dredging is not believed necessary to accommodate the presumed methanol tanker size (120,000 - 150,000 DWT tankers). If additional port facility expansion is required, it may be financed through the imposition of port fees, which fees were not considered for purposes of costing this project. Another potential transport mode from Fairbanks to Tidewater could be shipment of methanol through the TAPS line, with export through the port of Valdez. Again, storage facilities would be required and financed by the methanol plant sponsors; additional port expansion (wharfs, dredging, etc.) would probably not be necessary given the development undertaken to accomodate crude oil shipment from TAPS. The port of Valdez imposes a port charge (at $5,000/hr.) which could be applied toward wharf and dock expansion if and as necesary; again, these costs were not considered for purposes of project costing.

(2) **Rail shipment of methanol could provide a steady revenue stream to the Alaska Railroad, although some capital improvements are needed**

The intended transport mode of methanol from Fairbanks to Seward is via the Alaskan Railroad. This railroad is currently owned by the Federal government, although proposals to transfer ownership to the State have been advanced. If the methanol plant were constructed, it would provide an assured volume of shipment -- and a steady stream of revenue to the State. This income stream could be used for track expansion and improvement; some additional track would need to be laid from the current line to the plant gate (approximately eight miles), which trackage was not included in project cost. The discounted value of the rail tariff stream has been estimated at 58 million, although it could well be less if the plant sponsors are successful in obtaining a volume shipment discount from the railroad.

(3) The methanol plant offers an additional source of low-cost electricity with no State expenditure needed

Both Fairbanks gas use options assume that some portion of the North Slope gas will be used for electricity generation. In the case of the methanol plant, this cogeneration facility is financed by the plant's sponsors, with 98% of the electricity generated (1.9 million kWh/year) sold to local users, at an expected cost of 4.5¢/kWh. This price is well below the prevailing price of electricity in the Fairfanks area. Moreover, the State would be spared the necessity of building a 125 MW plant -- thus the saving approximately $100 million (based upon costs for gas-fired combined-cycle generating units). If project sponsor's expectations are met, this electricity supply could serve to stimulate development of an industrial park in the Fairbanks environs, which in turn could provide employment opportunities and enhance the property tax base.

(4) Gas-Fired Combined-Cycle Powerplants Represent a Level-Cost Power Source to Supply Railbelt Electricity Needs

Constructing generating stations to meet future Railbelt electricity requirements constitute an obvious addition to the State's infrastructure. This option confers additional economic benefits.

- **Low construction costs.** The cost of adding 736-1386 MW of gas-fired combined-cycle electricity generating capacity is estimated to be $586-1165 million (1982 dollars). This type of generation is relatively inexpensive to install -- $810/kW. Accordingly, State borrowing capacity and/or general fund revenues would be less strained.

- **Low retail electricity rates.** Depending upon the value of the gas consumed, retail electricity rates could be held to 6.5¢/Kwh or even lower. The State would not only benefit from development of the North Slope gas resource, but also could apply some portion of the royalty income toward

  - Reducing electricity prices in the Railbelt, or
  - Providing greater energy cost subsidies to consumers not directly connected to the power grid.

## 3. EMPLOYMENT EFFECTS OF EACH OPTION WOULD BE SUBSTANTIAL

From 2,500 to 27,100 man-years of construction employment would be created by the four ANS gas development options -- excluding EOR, for which insufficient data are available to assess employment opportunities (see Exhibit V-10). During the operations phase of each of the projects, a total of 319-435 permanent jobs would be created by ANGTS and TAGS, respectively, and a range of 45-267 jobs created in Fairbanks by the electricity generation and methanol options, respectively.

Indirect employment -- i.e., added jobs in services and ancillary local manufacturing -- would also be induced by construction and operation of these kinds of projects.

Exhibit V-10

DIRECT EMPLOYMENT CREATED BY ANS OPTIONS

| | CONSTRUCTION PHASE | | OPERATION PHASE | |
|---|---|---|---|---|
| Option | Man-Years Of Labor | Wages Paid ($ Billion) | Annual Employment | Annual Wages ($ Million) |
| ANGTS | 27,100 | $ 1.90 | 319 | $ 15.0 |
| TAGS | 25,834 | $ 1.80 | 435 | $ 21.0 |
| METHANOL PLANT | 5,208 | $ 0.36 | 267 | $ 12.6 |
| ELECTRIC GENERATION | | | | |
| - Low Demand | 2,500 | $ 0.20 | 45 | $ 2.1 |
| - High Demand | 5,000 | $ 0.35 | 105 | $ 4.9 |
| ENHANCED OIL RECOVERY (EOR) | Not Available | | | |

Source: Estimates of Booz, Allen & Hamilton, Inc. and Homan-McDowell (See Appendix G for further references.)

- From 4500 to 48,800 jobs would be induced in Alaska, beyond the direct project labor requirements, by construction of the ANS gas options as a result of temporary indirect employment

- From 570-780 permanent indirect jobs would be induced by ANGTS and TAGS, respectively; and

- From 80-140 permanent indirect jobs would be created in Fairbanks by the electricity generaion and methanol options, respectively.

The number of jobs that are indirectly created was calculated by multiplying direct employment by 1.8, since most estimates of this effect from previous analysis in Alaska average in the 1.5-2.0 range (see Appendix G prepared by Homan-McDowell).

It should be noted that, although the construction labor man-years for ANGTS and TAGS are similar in number, they may not be of like character because of different project phasing:

- ANGTS facilities in Alaska are proposed to be built over a six-year period, with a peak construction labor force of 10,350

- TAGS would be built over a nine-year period (e.g., from 1985 to 1994, assuming some delay in start-up of construction), with a somewhat lower, but more protracted peak force.

Two points are made as to the benefits of a protracted, versus one-time construction peak. On one hand, as suggested in the report of the Governor's Economic Committee, a less severe "boom" effect is likely to be experienced in Alaska if TAGS proceeds to construction, rather than ANGTS, with fewer of the kinds of adverse social and cultural impacts that were reported to accompany the construction of TAPS. However, the prolonged construction duration of TAGS raises the prospect that a more "permanent" construction workforce would be created, with more permanent kinds of indirect employment as well. More permanent employees will, in turn, require greater expenditures by State and local governments for the kinds of infrastructural improvements required to sustain higher population. In other words the TAGS "boom," while of less social and cultural intensity, may cost the State more dollars than would the ANGTS "boom." A more precise phasing plan for each is needed to determine the extent of State revenues that would be generated, that could offset these costs.

## 4. POTENTIAL SOCIO-ECONOMIC AND ENVIRONMENTAL ISSUES ARE IDENTIFIED WITH EACH OPTION

Although an in-depth analysis of socio-economic, cultural, and environmental impacts associated with each of the five Phase II North Slope gas options was considered to be beyond the scope of this study, an attempt was made to identify potential areas of impact, both positive and negative.

It should be noted that much of this discussion is conceptual in nature as there exist significant uncertainties in both the design and implementation of several of the options, uncertainties which influence the anticipated severity and probability of potential impacts. Only in one case -- an EIS prepared for Congressional consideration of the ANGTS option -- have these types of impacts been examined previously in any detail, and those results are neither summarized nor reexamined herein.

Several assumptions were followed in their development. We assumed, for example, that any construction associated with these options and subsequent operation of any constructed plants follows all applicable Federal, State, and local regulations. If an impact (particularly environmental) is identified, therefore, it reflects a professional judgment of the technical difficulty of emission controls, or simply that an emissions source has been added to the emissions inventory of an area. Other impacts are mentioned based on assumptions of market penetration for new fuel sources, or other assumptions tied to changes in economic activity or prices. These impacts are summarized, in point form, by option below.

(1) ANGTS

- The pipeline is to be underground, which eliminates aesthetic/ obstruction impacts associated with above-ground pipelines.
- The pipeline will not be highly heated, reducing the chances for permafrost melt.
- Routing of the pipeline does not require construction in undeveloped areas as its route follows previously developed corridors.
- Operation of a gas conditioning plant on the North Slope, even though emissions are controlled and comply with applicable law, will degrade present air quality.
- The project itself and opportunity to tap the pipeline as a fuel source will increase construction/industrial activity and attendant air/water/land quality effects. Air quality improvements are possible to the extent delivered natural gas is substituted for oil and/or coal otherwise in use.
- The route that is proposed for the pipeline avoids areas of native Alaskan habitation and subsistence activity.
- Employment growth will increase immigration, change work force composition, and increase employment of minorities.
- Increased economic activity will increase the demand for all goods and services and strain governments' ability to provide the same services over the short-term, until a flow of royalty dollars and other monetary benefits to the government has been established.

(2) TAGS

- The pipeline is to be underground, which eliminates aesthetic/obstruction impacts associated with above-ground pipelines.
- The pipeline will not be heated, reducing the chances for permafrost melt.
- Routing of the pipeline requires only limited construction in undeveloped areas as most of the route follows previously developed corridors. However, steps will be required to minimize disturbance to the natural environment at and near the proposed crossing of Cook Inlet.

- Avoids locating a gas conditioning plant on the North Slope and its associated environmental impacts, and substitutes a location in an area already developed by the petrochemical industry. However, added air and water emissions at Kenai are still involved as a result of construction and operation of gas conditioning, liquefaction, and port facilities.

- As with ANGTS, the project itself and opportunity to tap the pipeline as a fuel source will increase construction/industrial activity and attendant air/water/land quality effects. Air quality improvements are possible to the extent delivered natural gas is substituted for oil and coal.

- The route that is proposed for the pipeline avoids areas of native Alaskan habitation and subsistence activity.

- Employment growth will increase immigration, change work force composition, and increase employment of minorities.

- Increased economic activity will increase demand for all goods and services and strain governments' ability to provide the same services over the short-term until the project's monetary benefits have been established.

(3) <u>ANGTS or TAGS with a methanol plant and electricity cogeneration facility</u>

- To the degree that delivered natural gas and produced methanol is substituted for oil and coal, air quality improvements may result from reduced emissions from mobile and stationary sources, reducing or cancelling the contribution from the methanol or cogeneration plants.

- Employment growth will increase immigration, change work force composition, and increase employment of minorities.

- Increased economic activity will increase demand for all goods and services and strain governments' ability to provide the same services over the short-term until positive revenue benefits have been established.

(4) <u>ANGTS or TAGS with electrical generating plant</u>

- To the degree that delivered natural gas and electricity is substituted for fuel oil, air quality improvements are possible, effectively reducing or cancelling the emission contributions from the electrical generating plant.

- Employment growth will increase immigration, change work force composition, and increase employment of minorities.

- Increased economic activity will increase demand for all goods and services and strain government's ability to provide the same services over the short-term until positive revenue benefits have been established.

(5) Enhanced oil recovery

- Avoids all direct and indirect impacts associated with construction or use of pipelines as part of the other options.

- Possible fugitive emissions at well sites.

- To the extent that availability of gas spurs additional oil exploration and development, impacts from this increased activity are possible and must be evaluated.

- Socio-economic or cultural impacts are largely unknown but likely to be few.

*  *  *  *  *

In summary, we found that any combination of the projects we evaluated -- ANGTS, TAGS, and gas-based development at Fairbanks -- would produce substantial in-state benefits in terms of

- The value of gas royalty and severance tax payments to the State, together with the revenue contributions for State income and property taxes would be substantial (on a net present value basis over the life of the project)

  - $3.3-8.2 billion from ANGTS in most oil price cases
  - $5.6-10.6 billion from TAGS
  - $26-62 million from development at Fairbanks.

- Contributions to State infrastructure and employment would also be substantial.

- Socioeconomic, environmental, and employment effects would accompany any of the projects.

# VI. PROJECT RISK ANALYSIS

Each of the five projects evaluated in Phase 2 bears risks that could reduce its economic benefits. For each project, we considered:

- Legal and regulatory risks -- uncertainties and possible delays associated with securing the key legal and regulatory approvals necessary for the project to proceed to construction and operation.

- Political risks -- the prospects that the political climate surrounding the project could act to impede its success in securing all requisite project approvals.

- Marketability, positioning, and timing risks -- the possibility that changes in market receptivity or value (e.g., under a lower oil price scenario such as the "low prices" case), or unforeseen economic factors could thwart successful and timely implementation of the project's market strategy.

- Technological risks -- the prospects that any technology involved in the project could operate unsuccessfully, or less successfully than planned.

These risk factors are described below with regard to their potential effect on each of the five projects:

## 1. ANGTS INVOLVES THE LEAST RISK BECAUSE IT HAS THE FEWEST UNKNOWNS AND IS THE CLOSEST TO START OF CONSTRUCTION

Of the five projects and project concepts studied in this report, ANGTS is by far the most advanced in terms of having completed most of the steps that must preceed the onset of construction (see Exhibit V-1). A description of the key risks are as follows:

- The legal and regulatory risks surrounding ANGTS are among the least for any North Slope gas option we evaluated in Phase 2. With its routing and conveyance means (Alcan Highway and gas pipeline, respectively), as well as a package of waivers from key regulations approved by the Congress, ANGTS may legally proceed to construction after its financing and final regulatory approvals have been secured.

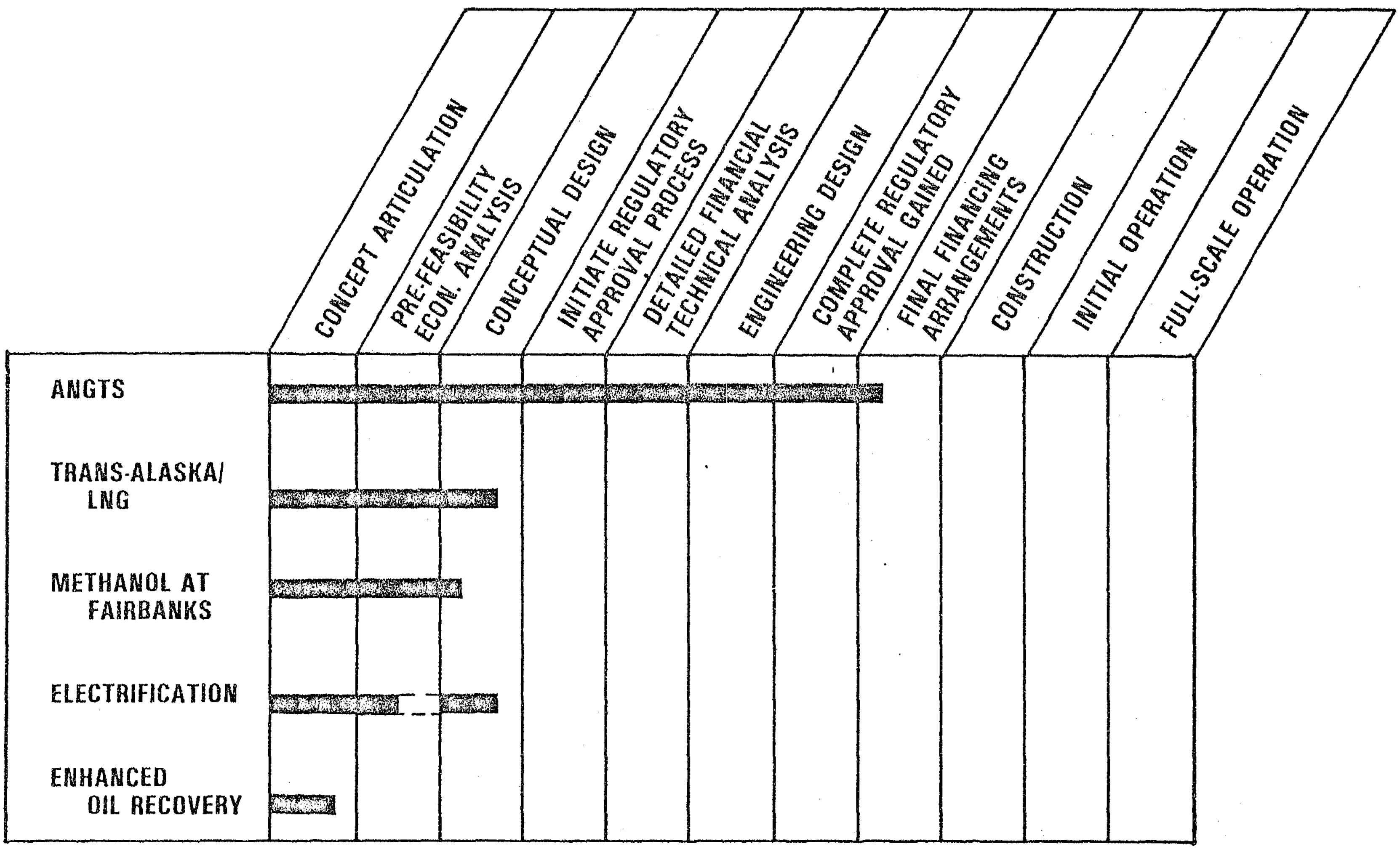
- ANGTS involves the least amount of political risk of any of the five options evaluated in Phase 2. This is the case because the Congress has already approved

  - In 1977, the ANGTA, which selects ANGTS as the preferred routing option

  - In 1981, a waiver package which was designed to expedite its financing.

Exhibit VI-1

THE ANGTS OPTION IS YEARS AHEAD OF OTHER NORTH SLOPE GAS ALTERNATIVES IN THE PROJECT CYCLE



Each of these Congressional actions involved wide debate and a visible affirmation of ANGTS on the part of those in Congress who supported the approvals. In such cases, political commitment develops for the project to proceed the way Congress intended, thus it becomes all the more difficult, although not impossible, for the Congress to "cancel" the project and sanction an alternative. In summary, the political risks of proceeding with ANGTS are few because sufficient political identification and commitment have already been secured.

- Marketability, positioning, and timing risks. Because the gas supply/demand/price outlook in the Lower 48 states has changed so significantly since ANGTS was initially proposed in 1976, its marketability risks are substantial. The prospect exists that domestic gas markets will evolve differently from the way the outlook is portrayed in our analysis.

- Technological risks. Risks associated with the kinds of technology proposed for deployment in ANGTS are confined chiefly to questions of pipeline construction practices in Arctic conditions. Experience gained from construction in the 1970's of the oil pipeline (TAPS) under similar routing and climatic conditions has substantially reduced the technological risk associated with ANGTS, as has the substantial engineering and technical work that have been undertaken by the project sponsors over the past 5 years.

## 2. DESPITE SOME OF ITS POTENTIAL ECONOMIC AND POLITICAL BENEFITS, TAGS HAS SUBSTANTIAL MARKET TIMING AND REGULATORY RISKS

Risks associated with TAGS relate chiefly to the impact of project delays in reducing its marketability.

- Legal and regulatory risks. A number of key legal and regulatory issues -- each of which could cause delays -- remain to be resolved before TAGS may proceed to construction. These include, but are not limited to:

  - Removal of ANGTS as the Congressionally-approved delivery system for existing North Slope gas reserves, a process that we believe would require Congress to act during the first session of the 98th Congress, if operation is to begin by 1988 as planned. Since no such legislation has been proposed (as of the date of this report), we conclude that the second session, or a subsequent Congress, will have to act on TAGS. Delay in approval of TAGS is highly likely, and therefore, start-up of its first phase in 1988 appears unlikely.

  - FERC approval of TAGS exclusively as an LNG export project would entail the least delay of any of its regulatory options. TAGS would still be subject to the Natural Gas Act, however, as is any gas export project (e.g., existing Cook Inlet sales of LNG to Japan). This approval process, if litigated (see Appendix H), would involve one to two years of delay, because of the current backlog of cases before the FERC, based on recent experience of other major proposals to come before the Commission. Furthermore, if a "gathering line" status for the TAGS pipeline is sought (e.g., on the premise that the gas conditioning plant would be located in southern Alaska), litigation delays are likely because the FERC has wide latitude in this determination.

- Political risks. From a political perspective, some of the same factors that tend to reduce the risks of ANGTS are factors that increase risks for TAGS, or any other North Slope gas option that must legally preempt ANGTS. In addition, the following risks are also involved for TAGS:

  - Failure to construct a pipeline across Canada would foreclose the prospects for handling gas that might potentially be produced from outreach production areas in northern Alberta and British Columbia. On this basis, Canadians could oppose TAGS.

  - Removal of ANGTS approval by the Congress is almost certainly a precondition for TAGS. This process involves substantial risk of delay, particularly because of the wide debate, and consequent legislative commitment, surrounding enactment both of ANGTA in 1977 and of the ANGTS waiver package in 1981.

  - The prospects for using North Slope gas anywhere in the Lower 48 states would also be foreclosed, unless an LNG receiving terminal is constructed on the U.S. West Coast. Even if such an LNG receiving terminal were to be constructed for use in part by TAGS (e.g., at Little Cojo Bay), or if TAGS gas were to be offloaded at one of the four existing U.S. East Coast LNG terminals, a recertification of TAGS as an interstate gas transmission system may be required. We view this as a political risk because some gas consumers in the U.S. Midwest states, who were supposed to receive North Slope gas via ANGTS, will argue that they have been circumvented.

  On the other hand, TAGS offers the following political advantages from an international perspective, which may act to counter the above political risks:

  - Improved balance of payments in general, and with Japan in particular

  - Improved U.S. strategic position in the Pacific Basin by possibly forestalling market entry of Soviet natural gas into Japan

  - Assisting Japan in its efforts to decrease its dependence on OPEC oil.

- Marketability, positioning and timing risks. Delay could reduce the viability of TAGS in two ways -- by raising its costs and by creating an opportunity for competing projects to complete LNG sales agreements in the Pacific Rim. In particular, as described earlier in this report, the risk exists that the prime market for TAGS gas, LNG consumption in Japan may shrink or disappear altogether. For example, if either reduced LNG demand in Japan -- or increased LNG supplies to Japan -- act to reduce LNG marketability to the extent that TAGS can only proceed to its first phase (approximately 350 Bcf per year), then the project would produce a negative wellhead netback value for its first five years.

- Technological risks. TAGS proposes to draw upon existing technology and experience, both in the pipeline industry (including work on TAPS in the 1970s) and in the maritime industry (including LNG shipping as far north as the port of Kenai). Because of this basis in known design and engineering precedents, even for the high-pressure untreated gas line, TAGS is not perceived as jeopardized by technological risk.

3. A METHANOL PLANT AT FAIRBANKS INVOLVES SOME MARKETABILITY RISK

To the extent that contracts for sale of product have not been fully obtained by the time construction has commenced, some price risk will exist for this project. Its other risks, particularly political and technical, are perceived to be minor in nature.

- Legal and regulatory risks. Because this project proposal is a gas-based chemical manufacturing facility, rather than a natural gas sales facility per se, the Natural Gas Act in unlikely to apply; thus, the FERC would not have to approve of the project, which reduces this area of possible delay. Other approvals would be required, however, including federal export approvals, as well as state approvals for use of water and air quality. Securing these approvals is not regarded as posing serious risks to this project.

- Political risks. Because this project would extend industrial development into the Alaskan Interior, and broaden the base of the Fairbanks economy, it is perceived as politically popular within Alaska.

- Marketability, positioning, and timing risks. The sizing of a methanol plant at 5,000 tons per day as opposed to a larger amount, is appropriate in view of

  - The world market for methanol which is likely to remain limited by an abundance of natural gas near the major U.S. and European markets throughout this project's useful life

  - The prospects that a lower world oil price scenario could occur, in which case petroleum products and natural gas could both be available at a lower price than methanol from Alaska.

- Technological risks. Both the methanol plant and the electricity cogeneration facility involve known, proven technologies, and thereby minimal technological risk.

4. MINIMAL RISK ATTENDS USE OF ANS GAS FOR IN-STATE UTILITY PURPOSES

Gas and gas-based electric utility service at Fairbanks involves few, if any, risks.

- Legal and regulatory risks. The Fuel Use Act (FUA) currently poses a barrier to construction of new gas-fired electricity generation at a scale envisioned in this option; however, this is not viewed as critical because waivers of FUA requirements have been granted in numerous past situations. Local approvals (e.g., easements in Fairbanks) would have to be obtained in order to construct a natural gas distribution network, however, which may involve delay. Other factors that could cause delay include obtaining a number of routine state approvals for construction and operation of the system, which are required as well.

- Political risks. As described above in the case of the methanol plant, a receptive political climate appears to exist in Alaska for extending the State's industrial base into the interior regions, thus little political risk is discernible.

- Marketability, positioning and timing risks. As indicated in Chapter III of this report, Alaskan demand for electricity is expected to increase at a significant annual rate, particularly under the more rapid oil price and economic growth scenarios. Therefore, the market positioning of an electric power plant appears to be favorable. Utility natural gas service is presently nonexistent in Fairbanks, however, and should a gas distribution system proceed to construction, marketability risks will depend entirely upon the utility service conditions (i.e., risk may or may not be built into the financial arrangements).

- Technological risks. Since all project components derive from existing engineering experience, including that gained under Arctic conditions, little technological risk is perceived.

5. TECHNOLOGICAL RISK SURROUNDS A MAJOR EOR UNDERTAKING AT THIS POINT, ACCOUNTING FOR THE MODEST SCALE OF ARCO'S CURRENT PROGRAM

Risks attendant to EOR use of ANS gas are as follows:

- Legal and regulatory risks. Reinjection of gas produced along with crude oil on the North Slope has been practiced since 1977, when oil sales began via the completed TAPS line. The Alaska Oil and Gas Conservation Commission recently approved an initial tertiary oil recovery program at ARCO's Flow Station 3. Gaining of further approvals for expanded EOR activities does not appear to pose substantial delays or risks that the project would not take place.

- Political risks. The political climate in Alaska is not viewed as a major inhibiting factor against expanded EOR activities because EOR need not preclude sale of the natural gas at a later date.

- Marketability, positioning and timing risks. The key risk involved in a large-scale EOR program is the risk that the price of oil will decrease to levels insufficient to recover the return on investment. However, since levels neither of capital investment nor levels of oil flow enhancement are known with any degree precision at this time, the risk of failure to recover a return on investment cannot be ascertained.

- Technological risks. Considerable unknowns surround EOR on the North Slope, which the ARCO Flow Station 3 program is designed to reduce.

* * * *

In sum, the risks we have looked at include:

- Legal and regulatory
- Political
- Marketability, positioning and timing
- Technological.

We have concluded from our analysis that TAGS appears to involve greater risk than ANGTS because of the criticality of its market timing and the expected high probability of delay and debate. Nevertheless, TAGS may have some key advantages politically which, if recognized, could serve to shorten its delays.

The other options -- gas-based developments at Fairbanks and EOR on the North Slope -- involve only minor levels of risk at the scale they have been proposed thus far.